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CHANGES TO GREEN POWER PROVIDERS PROGRAM DRAFT ENVIRONMENTAL ASSESSMENT

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Symbols, Acronyms, and Abbreviations

BTM	Behind-the-meter
BTU	British Thermal Unit
c-Si	Crystalline Silicon
Cd-Te	Cadmium Telluride
CAA	Clean Air Act
CCR	Coal Combustion Residuals
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DC	Direct Current
DER	Distributed Energy Resource
DPP	Dispersed Power Production
EA	Environmental Assessment
EIS	Environmental Impact Statement
EU	European Union
EUC	End-use Consumer
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gases
GP	Generation Partners
GPP	Green Power Providers
GPS	Green Power Switch
GSA	General Services Administration
GWh	Gigawatt-Hour(s)
HAP	Hazardous Air Pollutants
HHW	Household Hazardous Waste
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
kWh	Kilowatt-Hour(s)
LPC	Local Power Companies
MW	Megawatts
MWh	Megawatt-Hour(s)
MSA	Metropolitan Statistical Area(s)
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NO_2	Nitrogen Dioxide
NOX	Oxides of Nitrogen
NPDES	National Pollutant Discharge Elimination System
NREL	National Renewable Energy Lab
O&M	Operation and Maintenance
O_3	Ozone
PA	Participation Agreement
Pb	Lead
PM	Particulate Matter
PPA	Power Purchase Agreement
PSA	Power Service Area
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
QCN	Quality Contractor Network
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Certificates
SACE	Southern Alliance for Clean Energy
SEIA	Solar Energy Industries Association
SHE	Safety, Health and Environmental
SO2	Sulfur Dioxide

TSCA	Toxic Substances Control Act
TVA	Tennessee Valley Authority
U.S.	United States
USEPA	United States Environmental Protection Agency

CHAPTER 1 – PURPOSE AND NEED FOR ACTION

The Tennessee Valley Authority (TVA) is proposing to close its Green Power Providers (GPP) Program to new customers on December 31, 2019. TVA is also proposing to establish an alternative solution to assist residential customers interested in solar installations. These proposals would not affect customers that have already entered into participation agreements with TVA or those that apply by the closure date.

TVA is completing an Environmental Assessment (EA) in compliance with the National Environmental Policy Act (NEPA) to consider the environmental impacts of closing the GPP Program and implementing a new private-scale renewable generation offering beginning in 2020.

1.1 Purpose and Need for Action

TVA's GPP Program is an end-use consumer (EUC) generation dual metering program that began in 2003 as the Generation Partners (GP) Pilot Program.[1] It was developed in an effort to provide distributors the opportunity to support environmental stewardship while responding to the growing consumer interest in generating renewable power. It also provided customers with an alternative to net metering that was compatible with the existing power contracts between TVA and local power companies (LPCs). Participation in the program is optional for LPCs. Through the GPP Program, participating LPCs' residential and commercial EUCs with renewable solar, wind, low-impact hydro, or biomass systems sell all of the generation to TVA for the term of their 20-year Participation Agreement (PA) for a fixed kilowatt-hour (kWh) rate.

TVA has determined that the GPP Program is currently out of balance with the needs of the Valley for three main reasons:

1. Current and forecasted Program underutilization, supported by qualitative and quantitative market research, suggests that the GPP Program is no longer attractive to consumers;

2. Cost-shifting caused by distributed energy resource (DER) systems, including those enrolled in the GPP Program, results in an unfair burden on non-participants; and

3. Utility-scale solar is a lower cost solution than the private-scale generation systems enrolled in GPP.

<u>GPP Trends</u>

TVA annually evaluates its renewable offerings and consumer needs in light of evolving technologies, market pace, and fiscal responsibilities. Evaluation of the GPP Program indicates that interest in the program has been steadily declining over recent years. In the past, the program capacity was fully reserved most years. However, in 2018 only 2.5 megawatts (MW) out of the available 10 MW capacity was reserved, leaving 75 percent of the program capacity unutilized.

This trend is likely to continue as the GPP value proposition and process become less attractive and aligned with EUCs' expectations. When the GPP Program first began, TVA

[1] Dual metering refers to a situation where a customer has two meters, one that measures energy flowing from the grid to the household and another that measures energy flowing from the customer's renewable energy system to the grid.

offered generation rates that were well above retail rates for the renewable energy from the participating systems. At that time, the cost of solar photovoltaic (PV) was significantly higher than today and PV penetration was extremely low. High generation rates were aimed at stimulating renewable generation in the Valley by offsetting the high upfront cost of renewable installations. As the cost of solar PV decreased by more than 70% over the last decade (Solar Energy Industries Association 2019) and the DER market has evolved to offer lower cost renewable options, TVA has adjusted its GPP generation rates for private-scale systems accordingly.

Some EUCs, particularly residential EUCs, tend to focus more on the difference between the GPP generation payment and retail rates. When the GPP generation rates were above retail rates, some EUC perceived PV as a good investment. Current GPP generation payment rates – $0.09/kWh for Residential/GSA-1 systems under 10 kW and $0.075/kWh for all other systems eligible for the program – are no longer attractive to some potential solar participants. In some LPC territories, the GPP rates are slightly below the retail rates EUCs pay for their electricity. Additionally, market research conducted by a third party among Valley residents and solar installers indicated that the GPP process is not sufficiently simple or streamlined. The dual metering configuration required for GPP causes all energy generated by a renewable system to flow to the grid. This approach generally runs counter to some EUC's preferences to directly consume the electricity that their system generates.

Furthermore, installer, LPC, and market signals indicate a growing number of behind-the-meter (BTM) installations.[2] TVA projects that BTM will grow significantly in the coming decades (TVA 2019a), while GPP participation is projected to continue to decline (see Section 4.1.1). The current and expected future underutilization of the program in the marketplace is a strong indication that the GPP Program no longer meets the needs of the maturing market.

Consequently, in February 2019 the TVA Board approved the closure of the GPP Program, contingent on the satisfactory completion of any necessary environmental reviews under NEPA and other applicable federal laws. The Board also authorized the CEO to design and implement a program to replace the phased out GPP Program. This EA assesses the impact of closure of the GPP Program and of implementing a new service offering.

<u>Cost-shifting</u>
GPP was successful in stimulating investment in private-scale renewable energy installations by paying participants for the energy generated and delivered to TVA. In addition, when the program began, buying renewable energy from the EUCs was more cost-effective for TVA than constructing renewable generation sites. As a result, TVA originally paid premium rates for the renewable energy purchased through the GPP Program. These premium generation rates reduced the payback period of participants' systems leading to more installations than would have occurred without the premiums. The premium rates also contributed to the overall increase of renewable installations Valley-wide.

However, offering incentives or payments to adequately offset the initial investment for private-scale solar places a cost burden on non-participants, a result known as cost-shifting. In this context, cost-shifting occurs when TVA subsidizes GPP participants for the

[2] In a BTM installation, the EUC directly consumes the energy that their system generates. The system is "behind-the-meter" in the sense that the amount of energy generated and consumed is not monitored by the LPC.

energy they deliver to the grid by offering a rate that is higher than TVA's cost to generate the same amount of energy through other resources. The imbalance caused by over-compensation for DER energy, including energy produced by GPP participants, means that TVA and LPC costs must be raised for all EUCs, effectively shifting most of the costs of DER onto EUCs that have not installed DER.

Cost-shifting contradicts the principle of equity in energy pricing and creates an undue burden for those in lower income brackets who may not be able to afford solar but are paying to subsidize it (TVA 2018). Additionally, as discussed in TVA (2018), low-income households pay a higher percentage of income toward energy costs, creating a high energy burden. This analysis found that cost-shifting is likely to become more pronounced if the GPP Program is continued. As a public power entity charged with keeping energy rates as low as feasible, TVA is transitioning away from incentivizing private-scale solar installations to minimize cost-shifting to those who cannot install onsite solar.

Utility-Scale Solar is a Lower Cost Solution

Utility-scale solar has become a more cost-effective renewable energy solution to meet the energy needs of the Valley than private-scale solar installations.[3] This is because utility-scale solar benefits from economies of scale, where the average cost per unit of energy produced decreases as the size of the generation facility increases. As discussed in the 2019 Integrated Resource Plan (IRP), utility-scale solar is a more viable option for generating renewable energy when compared to building and commissioning other generation assets from any source, and TVA plans to increase its investment in utility-scale solar generation in the coming decades (TVA 2019a). Continued development of private-scale solar reduces the amount of energy TVA would generate at a lower cost, and therefore, effectively increases the system-wide costs of meeting the Valley's electricity needs.

1.2 TVA Proposed Action

In February 2019, the TVA Board of Directors approved closure of the existing GPP Program to new applications at the end of 2019. The Board also delegated authority to the CEO to provide for the design and implementation of new renewable offerings consistent with the Board-approved revised metering standard, making these decisions contingent upon the satisfactory completion of any environmental reviews necessary under federal law.

Under the Proposed Action, TVA would close its GPP Program to new applications on December 31, 2019. All current participation agreements (PAs), which outline the terms and rates that will apply to energy generated by GPP systems, will remain in effect for the remainder of their terms.

A new private-scale service offering would be implemented in 2020 and would be exclusively for residential EUCs interested in private-scale solar PV installations. TVA would establish a network of qualified solar installers for applicants to choose from for installing solar PV systems, installation standards that include best practices and requirements for installers, inspection requirements, and a more standardized

[3] Utility-scale solar refers to large solar generation facilities that are operated by utilities and managed in concert with utilities' other generation facilities.

interconnection process. The new program would be implemented in partnership with LPCs.

The proposed service offering takes into account market research conducted by an independent third party firm in the fall of 2018 with residential homeowners and installers. Quantitative testing was conducted among the homeowners in the Valley who have expressed interest in installing onsite solar and whose household annual incomes were greater than $75,000. The research highlighted that the public sees confidence in the quality of the solar installation as the most important benefit a TVA program can offer. Additionally, residential consumers generally assume they can use the power generated from a renewable system onsite, instead of selling it to a utility as they do under the current GPP technical buy-all/sell all arrangement. The solar installers indicated that marketing support and leads would be important features that a EUC renewables solution could offer.

Another aspect of the proposed service offering would address the disposal of solar arrays and related equipment after their useful life, which usually occurs around 20 to 25 years after installation. Many EUCs are not well informed on the proper disposal of arrays and the potential dangers of improper disposal. Incorporating training and increasing LPC and TVA visibility into private-scale installations may create opportunities to educate the public on proper disposal of solar arrays after they are no longer viable.

The proposed service offering would be available throughout TVA's power service area, shown in Figure 1-1.

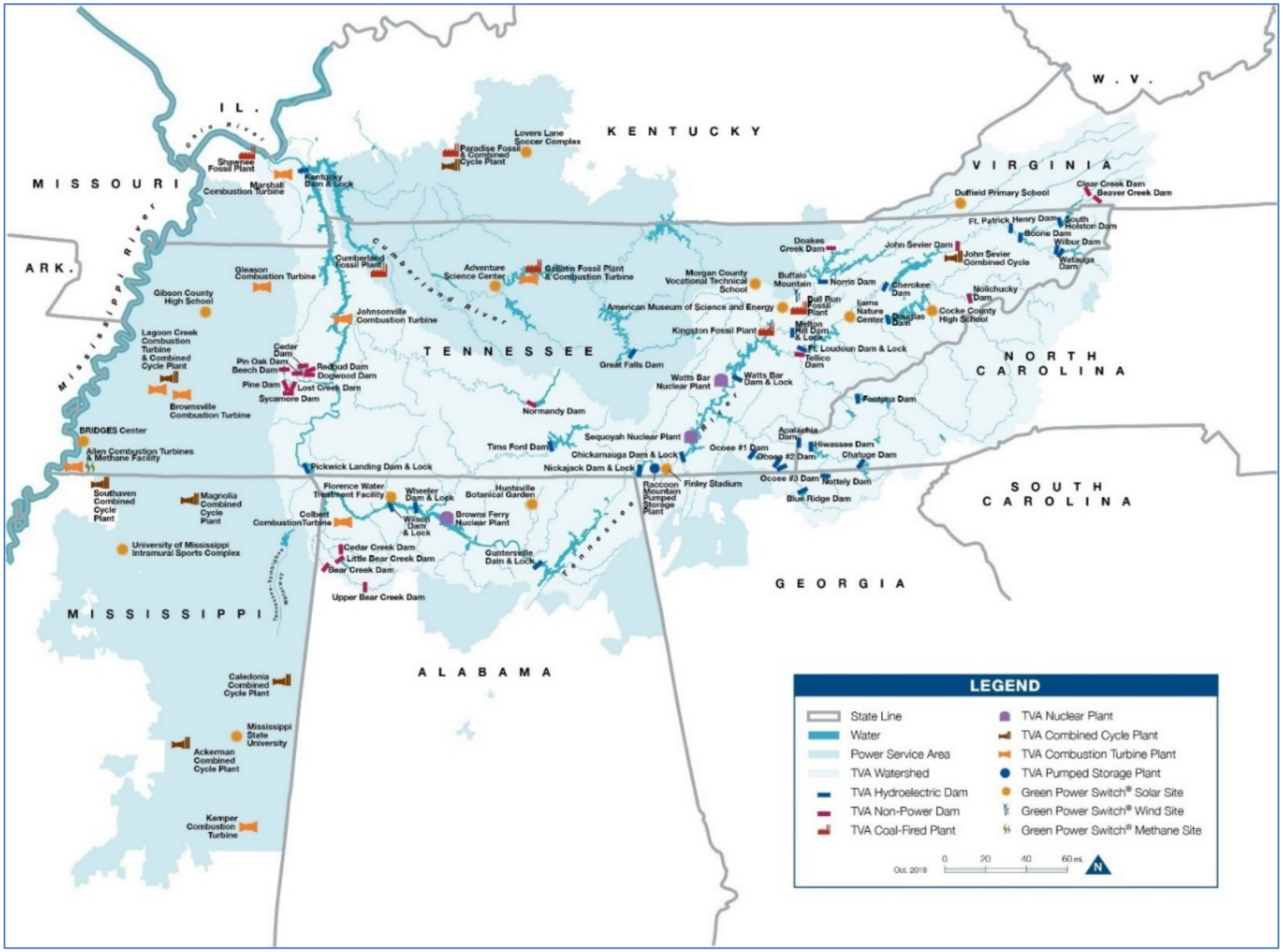

Figure 1-1. Power Service Area and Tennessee River Watershed (herein the TVA region)

1.3 Background

As noted above, the GPP Program has offered Tennessee Valley residential and commercial EUCs an opportunity to generate renewable energy in the TVA region. Under the program, participants install a small-scale renewable energy system on their property that is connected to the grid. These systems are considered a type of DER. TVA then purchases all of the energy produced by the system pursuant to a tri-party PA between TVA, the LPC, and the EUC. The energy purchase rate and other financial incentives of GPP have changed over time as private-scale renewable energy systems have become more affordable. The GPP PAs initially included a one-time incentive payment for enrolling in the Program and compensation for each kWh delivered to TVA at a premium above the retail rate to stimulate investment in private-scale renewable energy projects. The enrollment incentive and premium rate have not been offered in recent years.

1.3.1 History of GPP

In 2003, TVA started the GP Pilot Program that would later become GPP. Under the 2003 GP Pilot Program, TVA purchased renewable energy generated by facilities installed by residential, commercial, and industrial EUCs. Initially, only solar photovoltaic (PV) systems and wind turbines were included in the program. Later, eligible renewable system resources were expanded to include low-impact hydropower and systems using several types of biomass fuels. When the program first began, TVA purchased qualifying renewable generation at a fixed rate of $0.15/kWh via a generation credit on the participant’s monthly bill for a 10-year term.

In 2007, the TVA Board approved an official response to the Public Utility Regulatory Policies Act (PURPA), as amended the by Energy Policy Act of 2005. As part of the Board-adopted standard, the Board directed TVA to provide customers with the option to participate in a dual metering program “modeled after” the GP Pilot Program. The maximum capacity of individual systems installed under GP and GPP has varied from 1 MW_{DC} to the current limit of 50 kW_{DC}.

In 2011, the TVA Board adopted the GPP Program to replace the GP Pilot Program. The GPP Program operated similarly to its predecessor and was consistent with the metering standard TVA adopted in 2007. Qualifying generating systems could not exceed 50 kW direct current (DC) nor generate annually more than the customer’s usage at the site’s billing meter. The eligible renewable system resources remained the same as in GP. A 20-year PA included a $1,000 sign-up incentive and an energy generation credit at the retail rate plus a $0.12/kWh premium.

The $1,000 incentive was phased out for new non-residential participants in 2015 and for new residential participants in 2016. Additionally, the generation credit paid to participants decreased in concert with the significant decrease in the cost to install solar systems. See Table 1-1 for changes in the GPP payments over time.

Beginning in the 2016 program year, premium payments were eliminated. This change did not affect payment schedules under existing PAs. Generation payments for each kWh generated were set at the retail rate through the 2017 program year. For the 2018 program year, payments were decoupled from the retail rate and modified to the following schedule for the 20-year term: $0.09/kWh for Residential/GSA-1 systems under 10 kW, and $0.075/kWh for Residential/GSA-1 systems over 10 kW and non-GSA-1 Commercial.

Currently, 136 of the 154 LPCs offer GPP. Combined, the GP and GPP Programs have over 3,600 generating systems with a total nameplate capacity of about 110 MW_{DC}. Solar PV facilities comprise about 90 percent of this capacity. Biomass (landfill gas, wastewater methane, and wood waste and chips) comprise about 10 percent of capacity. Wind generation provides about 96 kW_{DC}, and small hydroelectric systems provide 9 kW_{DC}.

As noted above, the GP and GPP Programs were both historically offered to residential and commercial EUCs. Residential EUCs account for 60% of the generating systems, while commercial EUCs account for roughly 40%. However, because commercial EUCs tend to install larger systems, they make up almost 75% of the total nameplate capacity.

Enrollments in GPP have been declining in recent years. New GPP systems coming online have decreased from 560 in 2013 to 247 in 2018, a 56 percent decrease (Figure 1-2). New GPP capacity coming online has decreased from about 38.3 MW in 2011 to about 4.1 MW in 2018, an 89 percent decrease (Figure 1-3). This decline may be primarily caused by the reduction in GPP generation credit rates, as these are highly correlated to the number of residential systems coming online (Figure 1-4). In addition, EUCs that are willing and able to enroll in GPP may be participants who previously enrolled in the program.

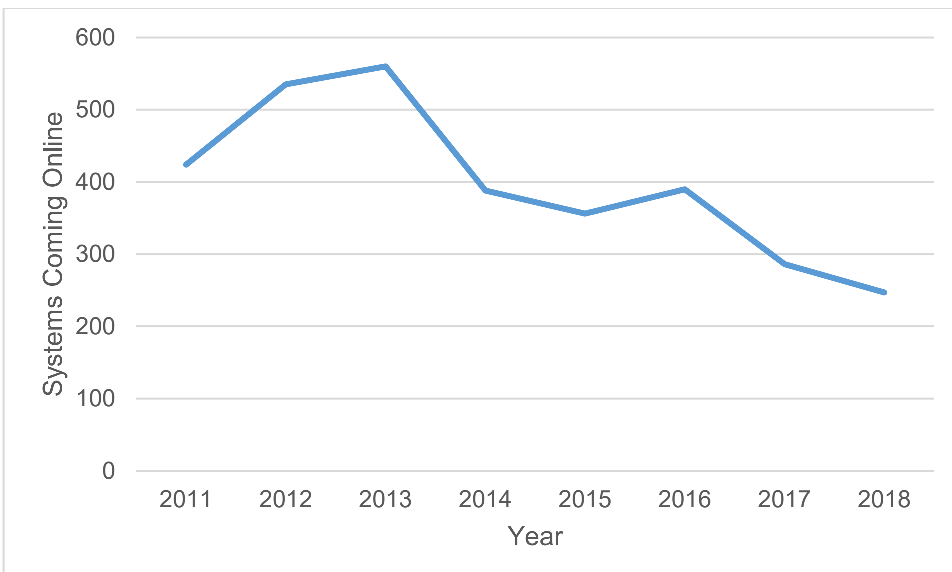

Figure 1-2. Number of New GPP Systems

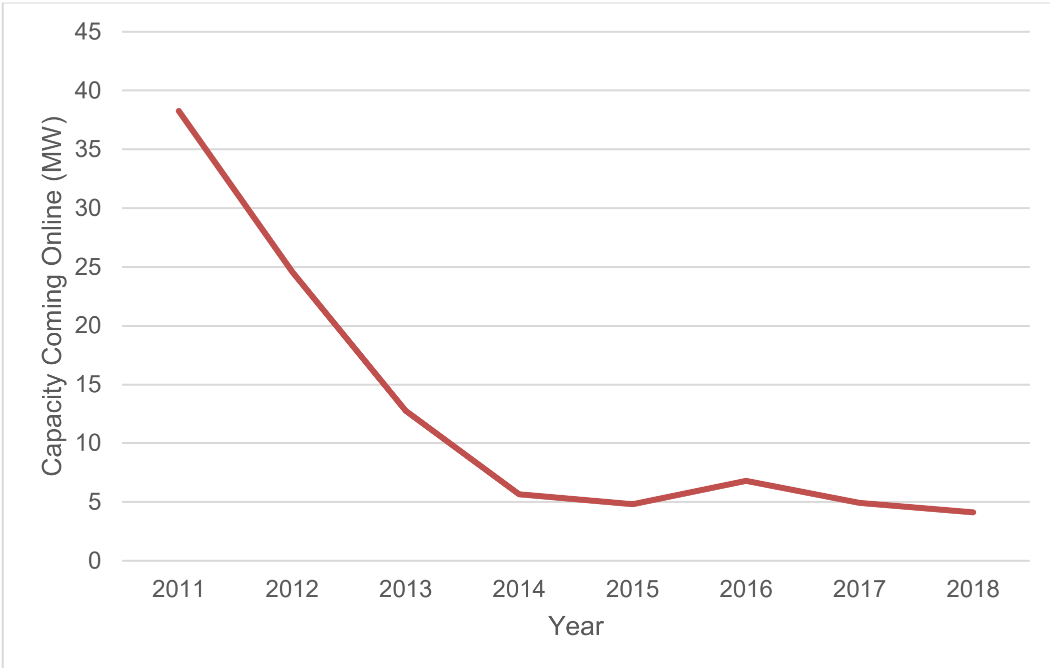

Figure 1-3. New GPP Capacity

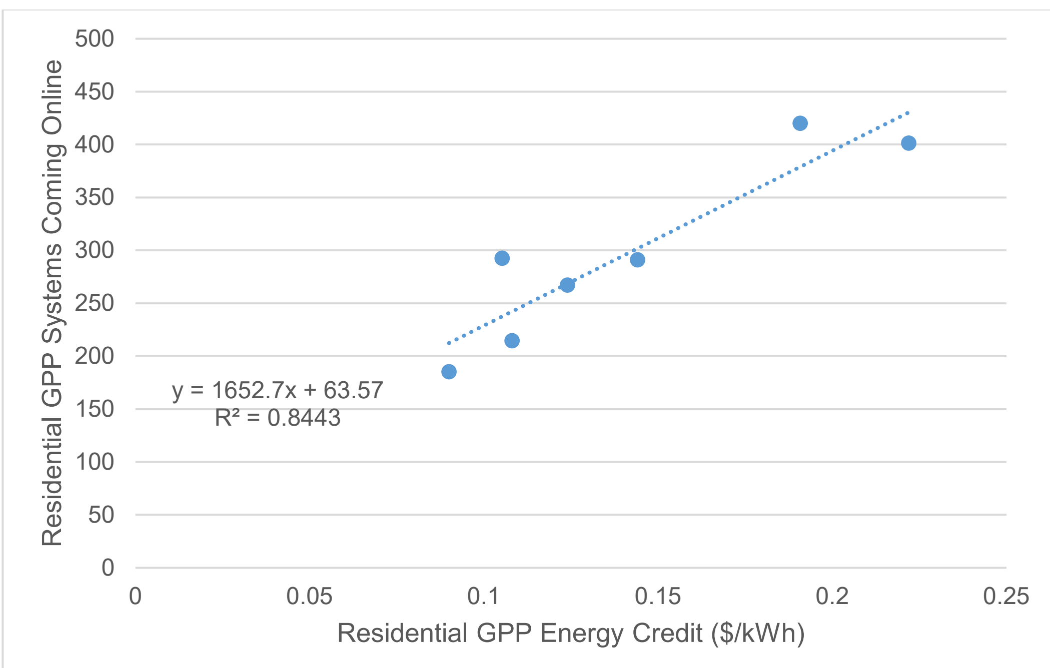

Figure 1-4. Relationship between New Residential Systems and GPP Energy Credit Rate

Table 1-1. GPP Payment Structure

Year	Generation Credit Rate	One-Time Incentive Payment ($)	Premium Rate (Solar) ($/kWh)	Premium Rate (Wind, Biomass, Hydro) ($/kWh)	Capacity Limit (MW)
2012	Retail	1,000	0.12	0 – 0.03 a	N/A
2013	Retail	1,000	0.09	0.03	10
2014	Retail	1,000	0.04	0.03	10
2015	Retail	0	0.02	0.02	10
2016	Retail	0	0	0	10
2017	Retail	0	0	0	10
2018	Residential < 10kW: $0.09/kWh Commercial/Industrial & Residential > 10 kWh: $0.075/kWh	0	0	0	10
2019	Residential < 10kW: $0.09/kWh Commercial/Industrial & Residential > 10 kWh: $0.075/kWh	0	0	0	7.5

Additional information on the GPP Program is available on TVA's webpage at: https://www.tva.gov/Energy/Valley-Renewable-Energy/Green-Power-Providers.

1.3.2 Other Private-Scale Renewable Options

The GPP Program is one of several options available for residential and commercial EUCs to support renewable energy in the TVA region. TVA offers other renewable energy programs to EUCs, and they also may install BTM renewable energy generation systems. Each of these options is summarized below.

Dispersed Power Production (DPP) Program

Since 1981, TVA has offered the Dispersed Power Production (DPP) Program to commercial and residential EUCs. The DPP Program satisfies the requirements of Title II of PURPA, under which electric utilities, including TVA and LPCs, are required to purchase power from Qualifying Facilities. Qualifying Facilities are defined by the Federal Energy Regulatory Commission (FERC) as power-generating facilities up to 80 MW whose primary energy source is renewable, biomass, waste, or geothermal resources; or cogenerating facilities that sequentially produce electricity and another form of useful thermal energy in a way that is more efficient than the separate production of both forms of energy. TVA complies with this requirement on behalf of its LPCs through the DPP Program. In 2018,

capacity of DPP was 157 MW (TVA 2019b). Under the DPP offering, participants have three configuration options:

1. Self-Generation: excess energy flows to grid and is not purchased by TVA;
2. Self-Generation and Dispersed Power Contract: excess energy flows to the grid and is purchased by TVA;
3. Dispersed Power Sell All Contract: all power generated is purchased by TVA.

Under the second and third options, the power is purchased at TVA's monthly avoided cost for the term of a 5-year contract. For reference, the current standard price for September 2019 is set at $0.0176/kWh (TVA 2019c). EUCs may have dual-meter or single bi-directional meter arrangements depending on which option they choose. While the maximum individual system size is 80 MW, there is no program capacity maximum. The system owner retains environmental attributes and Renewable Energy Certificates (RECs).[4]

Green Power Switch (GPS)

Residential and commercial EUCs who cannot install onsite generation or who are not willing or able to participate in the GPP or DPP Programs can support renewables through TVA's Green Power Switch (GPS) Program. GPS, the first renewable program to be founded in the Southeast, launched on Earth Day, April 22, 2000. Through GPS, EUCs can purchase Green-e energy certified RECs, currently sourced from Valley installations, specifically GPP solar and biomass installations and TVA's Buffalo Mountain Wind power purchase agreement (PPA). The GPS product is currently priced at $4 for a 150 kWh energy block. In 2018, participants purchased approximately 63 gigawatt hours (GWh) of renewable energy blocks through the GPS Program (TVA 2019b).

Behind-the-Meter (BTM)

Valley residents also have an option of installing solar systems BTM. A BTM system is a DER system that is located on a customer's property and is designed to supply power to a single building or facility. A BTM system allows the owner to use the energy generated by the solar system first and use the grid as a backup. TVA estimates that in 2018 there was approximately 700 MW of capacity from BTM generation, of which about 90 percent comes from combined heat and power systems (TVA 2018). The capacity of BTM solar in 2018 was estimated as 37 MW. To ensure the safety of BTM installation, EUCs are encouraged to contact their LPC to learn about the terms of the LPC's interconnection agreement.

1.4 Related Environmental Reviews and Consultation Requirements

TVA's consideration of the PURPA-promulgated net metering standard was addressed in TVA's *Public Utility Regulatory Policies Act Standards Final EA*, completed in 2007.

Another pertinent environmental review completed by TVA includes the *2019 IRP Final Environmental Impact Statement* (EIS; TVA 2019b), which describes the TVA power system and the anticipated impacts of its future operation. The information utilized for the assessment of effects from the proposed GPP Program changes reflects and encompasses the most current data and information available to TVA. Other environmental reviews of

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[4] A Renewable Energy Certificate (REC) is the accepted U.S. legal instrument representing property rights to the non-power attributes of renewable energy generation. RECs are used to substantiate claims of renewable electricity generation.

relevance include the *Alternative Electric Power Rate Structures Final EIS* (TVA 1980) and *Policies Relating to Electric Power Rates Final EIS, Volumes 1 and 2* (TVA 1976).

In 2015 and 2018, TVA also completed environmental reviews relating to rate changes. The *2018 Wholesale Rate Change EA* addressed the establishment of a wholesale grid access charge and the application of an equivalent reduction in rates. This change in the wholesale electric power rate structure was needed to better align wholesale rates with the underlying costs to serve wholesale customers.

Each review discussed aspects of TVA's fundamental rate structure and customer classes and its historical relationship with the electricity sellers (the distributors) and consumers in the Tennessee Valley region. Both the 1976 and 1980 EISs and the 2015 and 2018 EAs concluded that the timing and magnitude of resulting impacts on the physical environment (air, water, land, and other primary natural resources) were somewhat speculative, primarily because rate change (and rate adjustment) effects on the physical environment depend on numerous decisions to be made by persons and entities outside TVA's control. Despite these uncertainties, the EISs and the EAs concluded that in all likelihood any resulting physical environmental impacts would be insignificant.

1.5 Public Involvement

TVA has worked with LPCs and other stakeholders to inform the new service offering in Alternative C. This collaboration includes market research on households' preferences across potential service offerings. Additional detail is provided in Chapter 1 and Section 2.1.3.

On October 9, 2019, TVA issued this draft EA for public review and comment. TVA provided notice to the public of the review period via a media advisory, notices in key regional newspapers, and outreach to key stakeholders. TVA posted the draft EA on its webpage (www.tva.gov/nepa) with information about how to submit comments. TVA will consider the public's input when completing the final EA and will provide responses to public comments.

1.6 Necessary Permits or Licenses

Because there are no state or federal permits or licenses required for TVA to undertake this action, TVA has not consulted with other agencies relating to the proposal.

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CHAPTER 2 - ALTERNATIVES

This chapter describes the three alternatives analyzed in this EA, summarizes the environmental impacts associated with each alternative, identifies potential mitigation measures, and presents the preferred alternative.

2.1 Description of Alternatives

2.1.1 Alternative A – No Action Alternative (GPP Program Continues)

Under Alternative A, TVA would continue to implement the GPP Program, and there would be no changes to the services or offerings currently available to customers with private-scale renewable generation. The 2019 electricity purchase rates ($0.075 or $0.09 per kWh, depending on system capacity) would remain the same and the annual total GPP capacity limit for new enrollments would revert to the 10 MW capacity limit set each year between 2013 and 2018, up from the 2019 limit of 7.5 MW. TVA would continue offering DPP and REC purchasing programs to residential and commercial EUC interested in renewable energy. EUCs would also have the option of installing BTM generation.

2.1.2 Alternative B – Discontinue GPP Program without Replacement Program

Under Alternative B, TVA would close GPP to new applications effective 5:00 PM CST on December 31, 2019, and offer no replacement solution for private-scale renewable generators. Existing GP/GPP PAs and applications submitted prior to the closure date would continue for the duration of the agreement terms.

TVA would continue offering DPP and REC purchasing programs to residential and commercial EUCs interested in renewable energy. EUCs would also have the option of installing BTM generation.

2.1.3 Alternative C – Discontinue GPP Program and Present New Offering

Under Alternative C, TVA would (1) close GPP to new applications effective 5:00 PM CST on December 31, 2019, and (2) implement a new private-scale service offering shortly after GPP closure. Existing GP/GPP PAs and applications submitted prior to the closure date would continue for the duration of the agreement terms.

The new private-scale solar offering would not include contracts for sale of renewable energy or payments for energy generated by the EUC systems. Rather, the offering would be structured to include features and benefits identified as important by Valley residents and installers during market research conducted for TVA by a third party vendor. The surveyed EUCs identified “confidence in the quality of the installation” as the most important benefit a TVA program could offer and installers pointed to marketing and support as important features. The service offering would be exclusively for residential rate-class EUCs interested in installing private-scale solar PV systems. LPCs would have to elect to participate in the offering for it to be available in their service territory, just as they elect to participate in GPP today.

TVA proposes to establish (1) a Quality Contractor Network (QCN) of vetted solar installers for applicants to choose from when installing their solar systems, (2) installation standards that include best practices and requirements for PV systems and batteries, (3) inspection requirements, and (4) a more standardized interconnection process. The solar installers participating in the QCN would be licensed and insured, have completed special training on TVA installation standards and best practices, and maintain high customer satisfaction. In

return TVA would publicly showcase the solar QCN installers on the private-scale offering website. QCN members could also potentially benefit from more productive leads originating from this website since interested EUCs would have access to educational materials, which could be used to decide whether a solar system is the right investment for their property. The educational materials would include modules on the ideal placement and size of a solar system, insight into the technical set-up and functions of a solar system, and a link to the TVA solar calculator; the EUCs would have access to these resources prior to, during, and post installation. Further, the program website would offer a scheduling feature for the installation and inspection process. With the new structure, TVA and LPCs would have visibility into private-scale installations, which is crucial for safety of LPC and/or TVA personnel and equipment.

Another aspect of the proposed service offering would address the disposal of solar arrays and related equipment after their useful life, which usually occurs around 20 to 25 years after installation. Incorporating training and increasing LPC and TVA visibility into private-scale installations may create opportunities to educate the public on proper disposal of solar arrays after they are no longer viable.

TVA would continue offering DPP and REC purchasing programs to residential and commercial customers interested in renewable energy. Customers who participate in the private-scale offering could also participate in DPP and REC purchase programs pursuant to the terms of those programs.

2.2 Comparison of Alternatives

This section summarizes TVA’s findings in Chapter 4 of the EA. Consistent with past environmental reviews completed by TVA that relate to this proposal, TVA has initially identified the following resources and issues as potentially affected by the proposal:

- Energy production and use,
- Socioeconomics,
- Air resources,
- Water resources,
- Land use, and
- Production of solid and hazardous waste.

Because changes to GPP would occur throughout the TVA Power Service Area (PSA), potential impacts are evaluated in the context of the TVA PSA. As discussed in Section 4.1, future electricity generation through the GPP Program is a small fraction of the total and renewable electricity generation in the TVA PSA. The best projection is that future GPP electricity generation represents at most 0.1 percent of total electricity generation in the TVA PSA, while the upper bound scenario is 0.2 percent (Table 4-6). Of the renewable generation in the TVA PSA, the projected GPP generation would be between 0.5 percent and 1.5 percent (Table 4-6). Because the projected generation is so small in relation to total and renewable generation, any changes in TVA electricity generation operations under the three alternatives would not be discernable in the context of the TVA PSA.

Potential impacts to socioeconomics consist of three main factors. First, future potential GPP participants are directly affected by the alternatives, which either allow future GPP enrollment (in Alternative A) or disallow enrollment after 2019 (Alternatives B and C). Second, changes in DER adoption has the potential to affect the amount of cost-shifting in the TVA PSA. Third, the replacement service offering in Alternative C could directly impact future potential DER adopters and current adopters.

Compared to current conditions, future potential GPP participants would have a minor financial benefit under Alterative A associated with GPP energy credits. Alternatives B and C would eliminate this opportunity, which results in a minor negative financial impact to these individuals compared to Alternative A. Additional DER in Alternative A could result in \$5 million to \$14 million of cost-shifting, based on the best estimate and upper bound scenarios, respectively (Section 4.2.1). Cost-shifting represents an increase in costs to all EUCs resulting from installation of private-scale DER. The amount of cost-shifting in Alternative A is considered minor. Alternatives B and C would minimize cost-shifting caused by TVA's subsidies to DER adopters that would occur through the GPP Program in Alternative A. However, some EUCs would likely install BTM if GPP were not available, which would still result in additional cost-shifting compared to current conditions. However, this cost-shifting would most likely be less than cost-shifting in Alternative A.

The replacement service offering in Alternative C would focus on system quality and safety. This program would benefit future potential private-scale solar adopters. Alternative C would also provide safety benefits to both EUCs and TVA and LPC workers. The information provided by TVA on the proper disposal of solar systems could also benefit current and future DER adopters.

Under all alternatives, potential adverse impacts, such as increases in energy bills due to cost-shifting, would generally be spread across all EUCs in the TVA PSA. No disproportionately high adverse impacts on low-income or minority populations have been identified in any of the alternatives.

The potential for the alternatives to result in impact on air and water quality are highly dependent on whether the alternatives would require TVA to modify its electricity generation operations. Because there would be no discernable changes to TVA's energy generation operations under any of the three alternatives, any impacts to air and water resources would not be discernable under the alternatives.

Land conversion, clearing, or modification is generally not associated with private-scale solar systems typical for those enrolled in the GPP Program. When ground mounting is proposed, the 500 square feet of land required for the typical 5 kW residential system represents a small fraction of the approximately 25,000 acres currently used to support energy production in the TVA PSA (see Section 3.5). Under all three alternatives, the potential for land conversion is assumed to be a small fraction of the overall area currently used to support energy production in the TVA PSA. Therefore, any potential land use impacts are minor for each alternative.

Solid and hazardous wastes are associated with changes in total energy use, the renewable to non-renewable energy mix, and/or wastes generated as part of system installation and disposal. Under Alternative A, there would be minor increases in the production of solid and hazardous waste compared to current conditions as a result of new users installing systems, and thus, minor negative environmental impact would occur.

Alternative B would result in a minor increase equal to or lower than that of Alterative A based on EUCs adoption of BTM systems. Alternative B, therefore, also represents a minor negative environmental impact. Alternative C eliminates waste resulting from future potential GPP participation and provides guidance on the proposer disposal of solar panels to all DER adopters, which is likely to result in a minor positive environmental impact.

Table 2-1. Summary and Comparison of Alternatives by Resource Area[a]

Resource Area	Impacts by Alternative		
	A	B	C
Energy Production and Use	Minor changes in energy production and use; no discernable impacts on TVA operations	Minor changes in energy production and use; no discernable impacts on TVA operations	Minor changes in energy production and use; no discernable impacts on TVA operations
Socioeconomics and Environmental Justice	Minor positive financial impacts to future GPP participants; minor negative impacts to non-participants due to cost-shifting	Minor negative financial impacts to future GPP participants; minor positive impacts to non-participants	Substantively similar as for Alternative B; quality and safety benefits for future DER adopters
Air Resources	Not discernable	Not discernable	Not discernable
Water Resources	Not discernable	Not discernable	Not discernable
Land Use	Minor Negative	Minor Positive	Minor Positive
Production of Solid and Hazardous Waste	Minor Negative	Minor Negative	Minor Positive

[a] Note: The impacts for Alternative A are compared to current conditions, and the impacts for Alternatives B and C are compared to Alternative A.

2.3 Identification of Mitigation Measures

TVA has not identified any mitigation measures necessary to offset or reduce the level of impacts of the alternatives.

2.4 The Preferred Alternative

Alternative C, ending new GPP enrollment at the end of 2019 and offering a new private-scale renewable service offering, is the TVA preferred alternative.

CHAPTER 3 – AFFECTED ENVIRONMENT

This chapter describes the natural and socioeconomic resources that could be affected under the three alternatives. Because the alternatives would apply to the entire TVA PSA, the resources are described at a regional scale. The primary study area, hereinafter called the TVA region, is the combined PSA and the Tennessee River watershed (Figure 1-1), including all counties in Tennessee and portions of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia. The TVA PSA is comprised of 202 counties and approximately 59 million acres.

3.1 Energy Production and Use

The 2019 IRP and associated EIS, incorporated herein by reference, describe TVA's current and projected future energy generation system in detail (TVA 2019a and 2019b). This section provides a brief overview of key information.

3.1.1 Overview

TVA is the largest public power supplier in the United States. Dependable generating capacity on the TVA system is approximately 38,000 MW. TVA generates most of this electricity with 3 nuclear plants, 6 coal-fired plants, 9 simple-cycle combustion turbine plants, 8 combined cycle plants, 29 hydroelectric dams, and 14 small PV facilities. A portion of delivered power is also provided through long-term PPAs. TVA transmits electricity from these facilities over 16,000 circuit miles of transmission lines. Like other utility systems, TVA has power interchange agreements with utilities surrounding its region and purchases and sells power on an economic basis almost daily.

Consumers of TVA-generated electricity consist of a mix of residential, commercial, and industrial EUCs in the PSA. Recent (2009–2018) energy sales totaled between 133,000 and 163,000 GWh annually, with sales in fiscal year 2018 of 162,933 GWh. This included sales to 154 distributors serving residential, commercial, and industrial EUCs and 58 directly served large industrial customers and federal installations. In 2018, 21 percent of TVA's power supply was from coal; 39 percent from nuclear; 27 percent from natural gas; 10 percent from hydroelectric; 3 percent from wind; and less than one percent each from solar and biomass (see Figure 3-1). Overall, 13 percent of 2018 generation was from renewable sources.

The 2019 IRP found that in the current outlook scenario, future capacity requirements were similar to current requirements until the end of the 20-year planning horizon; at that time, required capacity was projected to increase slightly. However, the IRP reports that new generation resources will be needed to replace facilities that will be retired during the planning horizon. Further, the IRP reports that expansion of solar resources, including a combination of utility-scale and private-scale solar, is a key component of meeting future energy needs. The recommended power supply mix in the IRP envisions adding between 1,500 and 8,000 MW of solar by 2028 and up to 14,000 MW by 2038 if a high level of load growth materializes. This is a large potential increase compared to the current solar capacity of approximately 148.4 MW, which consists of about 110 MW_{DC} of DER enrolled in GPP, 37 MW of BTM solar DER, and 1.4 MW generated by TVA-owned small PV installations.

Importantly, TVA's 2019 IRP modeling found that future utility-scale solar capacity is expected to be much higher than future private-scale solar capacity in the TVA PSA across

all scenarios and strategies considered. The IRP's base case strategy, in which the least-cost generation mix that meets projected energy needs is selected, preferred utility-scale generation over private-scale solar due to its lower cost per unit.

The Southern Alliance for Clean Energy (SACE) produces an annual solar energy report covering states in the southeast United States. The 2018 report provides a forecast for distributed solar capacity until 2022 (SACE 2019). The geographic areas of analysis in the SACE report are states and therefore cannot be fully aligned with the geographic boundaries of the TVA PSA. However, the increase in distributed solar capacity is generally in the same range as developed in this analysis. For example, the state of Tennessee is forecast to experience an 83 percent increase in non-utility distributed solar capacity between 2018 and 2022 (SACE 2019). This analysis projects an increase of 118 percent over the same time frame in TVA's higher set of projections.[5]

3.1.2 Renewable Energy in the TVA Region

TVA's 2019 IRP and associated EIS discuss TVA's current energy generation mix in detail (TVA 2019a and 2019b). Total generation in FY2018 was 162,933 GWh, including both TVA generation and purchased power. Renewables comprised 21,232 GWh or 13 percent of the total (Figure 3-1).[6] The vast majority of renewable energy generation is hydroelectric and wind (a combined 96 percent), with solar and biomass each comprising between one and three percent of renewable energy generation (Figure 3-2).

[5] This is based on Projection 2. Projection 1 focused only on GPP capacity and therefore is not comparable.
[6] Renewables includes hydroelectric, wind, solar, and biomass.

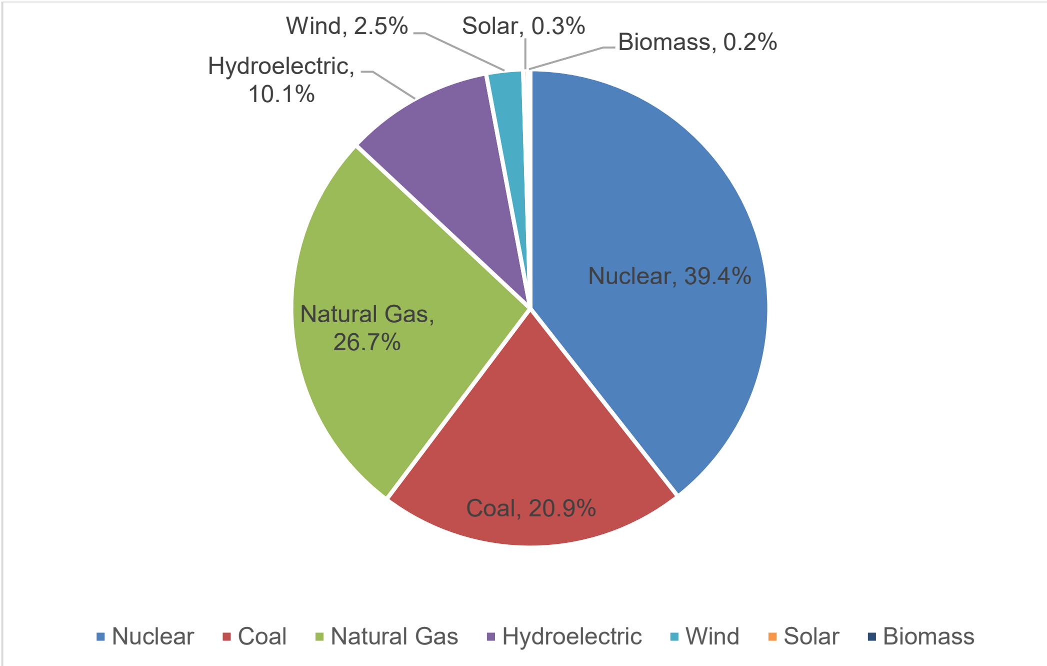

Figure 3-1. TVA 2018 Energy Generation

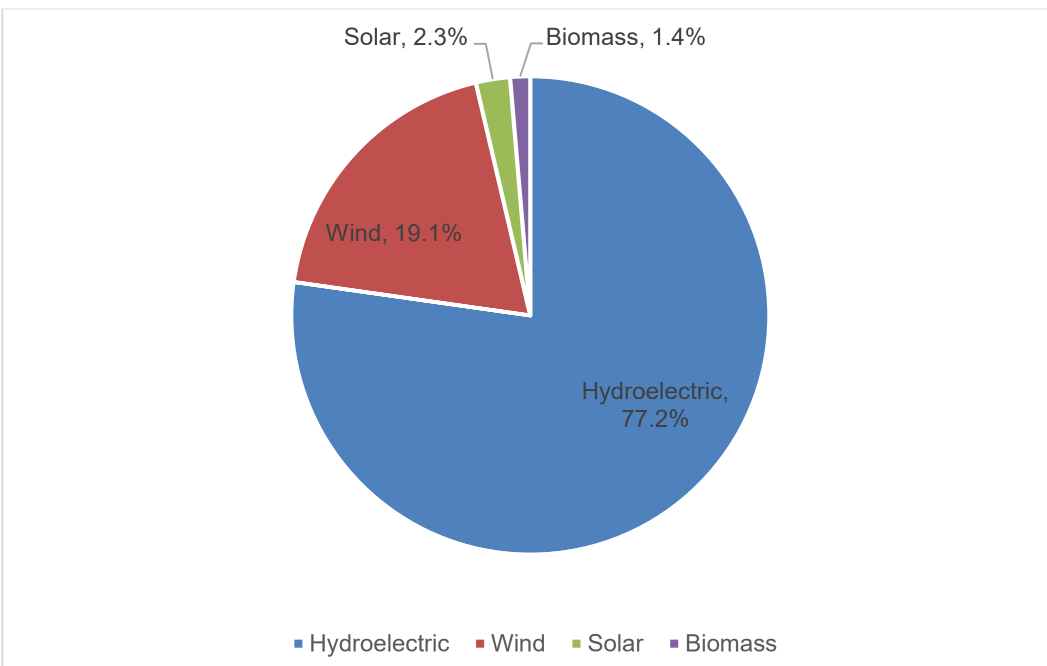

Figure 3-2. TVA 2018 Renewable Energy Generation

The DER options discussed in Section 1.3.2 have a combined capacity of 967 MW, of which the GPP Program makes up 11 percent (Table 3-1). In its IRP study, TVA estimated that GPP systems generated approximately 200 GWh of power in 2018, which is less than 1 percent of the total renewable generation and about 0.1 percent of total energy generation in the TVA region.

Table 3-1. Capacity of Distributed Generation Systems in 2018 [a]

Distributed Generation Option	Capacity (MW_{DC})	Proportion
Green Power Providers (GPP)	110	11.4%
Distributed Power Production (DPP)	157	16.2%
Behind-the-Meter (BTM)	700	72.4%
Total	**967**	**100.0%**

[a] Green Power Switch (GPS) is not included here because energy is not generated by the EUCs and would overlap with GPP energy generation.

3.2 Socioeconomics and Environmental Justice

This section summarizes the social and economic conditions in the TVA service area. This EA incorporates by reference the socioeconomic conditions and trends of the TVA region that are discussed in detail in the *2019 IRP EIS* (TVA 2019b) and *2018 Wholesale Rate Change EA* (TVA 2018).

3.2.1 Overview

The population of the TVA region was 10.3 million in July 2017, a 4.4 percent increase from July 2010. TVA projects that the rate of population increase in the TVA region will slow in the coming decades. Population density varies substantially among counties in the region, which contains a mix of rural and metropolitan areas. More populated areas are generally located along larger river corridors. About two-thirds of the population lives in defined metropolitan statistical areas (MSAs). As of July 2017, there are four MSAs with populations over 500,000, all located in Tennessee: Nashville (population of 1.9 million), Memphis (1.3 million), Knoxville (0.9 million), and Chattanooga (0.6 million). The largest metropolitan area in the TVA region located outside of Tennessee is Huntsville, AL, with a population of 0.45 million as of July 2017.

Selected social, demographic, and economic characteristics for the TVA region and the United States are presented in Table 3-2 (data from TVA 2019b). Primary observations include:

- The population of the TVA region is slightly older and includes a higher proportion of persons self-identifying as “white alone” than in the United States as a whole;
- The economy of the TVA region has a slightly higher percentage of workers employed in “blue collar” occupations such as natural resources, construction, production, and transportation than the nation as a whole and the proportion of persons with at least a high school degree was 84.7 percent, slightly lower than the national average; and

- The unemployment rate in the TVA region and the proportion of persons below the poverty level is higher than the national average, and per capita income is lower than the national average.

Table 3-2. Selected Social, Demographic, and Economic Characteristics

Characteristic	TVA Region	United States
Median Age	40.8	37.7
% Age 65 or Older	15.3	14.5
% High School or Higher	84.7	87.0
% Minority	26.3	38.7
Unemployment Rate (%)	7.7	5.8
Per capita income ($)	42,578	51,640
% Below Poverty Level	19.7	12.7
% Employment in Management, Business, Science, and Arts Occupations	32.9	37.0
% Employment in Service Occupations	16.8	18.1
% Employment in Sales and Office Occupations	24.1	23.8
% Employment in Natural Resources, Construction, and Maintenance	9.4	8.9
% Employment in Production, Transportation, and Material Moving	16.8	12.2

Source: *2019 IRP EIS* (TVA 2019b).

3.2.2 Minority and Low-Income Populations

Potential environmental justice impacts are analyzed in accordance with Executive Order 12898, which instructs Federal agencies to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of federal programs, policies, and activities on minority populations and low-income populations. While TVA is not subject to this Executive Order, it routinely considers environmental justice impacts in its NEPA review processes.

The *2019 IRP EIS* presents recent information about the geographical distribution of low-income and minority populations within the TVA PSA. Because the Alternatives considered herein would apply throughout the TVA PSA, this EA summarizes system totals. Refer to TVA (2019b) for more detailed information.

This EA also incorporates by reference TVA's *2018 Wholesale Rate Change EA*, which discusses energy use and the proportion of income spent on energy in the context of low-

income and minority populations. The *2018 Wholesale Rate Change EA* discusses that, in general, low-income households tend to use less energy than higher-income households but spend a higher proportion of their incomes on energy bills. Also within the TVA region, minority households are more likely to be low-income households than non-minority households.

3.2.3 Households with Distributed Energy Resources

The primary direct impact of the alternatives considered in this EA would be the discontinuation of the GPP Program including payments to prospective new enrollees. As such, the socioeconomic characteristics of households that invest in DER or participate in renewable energy programs are of particular interest.

A recent study found that households that adopt rooftop solar systems tend to have higher monthly electricity bills and higher incomes, have residents with higher education levels, and be over 50 years old, compared to non-adopters (Moezzi et al. 2017). As that study notes, these findings match the results of other research. The study also found that saving money was the primary factor driving households' decisions regarding rooftop solar. Environmental considerations were often cited as important but secondary considerations.

3.3 Air Resources

Ambient air quality is protected by federal and state regulations. With authority granted by the Clean Air Act (CAA) 42 U.S.C. 7401 et seq. as amended in 1977 and 1990, the United States Environmental Protection Agency (USEPA) established National Ambient Air Quality Standards (NAAQS) to protect human health (primary standards) and public welfare (secondary standards).[7] The USEPA codified NAAQS in 40 CFR Part 50 for the following "criteria pollutants": nitrogen dioxide (NO_2), carbon monoxide (CO), ozone (O_3), sulfur dioxide (SO_2), lead (Pb), particulate matter (PM) with an aerodynamic diameter equal to or less than 10 microns (PM10), and PM with an aerodynamic diameter equal to or less than 2.5 microns (PM2.5).[8] These NAAQS reflect the relationship between pollutant concentrations and health and welfare effects. Areas not meeting the standards are called "nonattainment" areas. There are no nonattainment areas designated within the TVA PSA.

TVA coal-fired and natural gas fired electric generating facilities either directly emit these pollutants or contribute to their formation (O_3 and PM2.5) in certain atmospheric conditions. Generally, TVA's hydro, nuclear, and renewable energy facilities do not directly contribute to air emissions. TVA has also installed air emission controls at its fossil fueled facilities to reduce air emissions. For instance, TVA has installed selective catalytic reduction systems on 21 of its coal units and on all of its natural gas fired combined cycle plants to reduce nitrogen oxide emissions. TVA has also equipped 60 percent of its coal-fired capacity with scrubbers to address sulfur dioxide emissions. These emissions are expected to go down even further when coal-fired units at Allen Fossil Plant are replaced with a combined cycle gas plant.

Hazardous air pollutants (HAPs) are those that are listed under Section 112(b) of the CAA because they present a threat of adverse human health effects or adverse environmental effects. The CAA requires the USEPA to regulate HAPs from listed categories of industrial facilities. HAPs are toxic air pollutants, which are known or suspected to cause cancer or other serious health effects or adverse environmental conditions. The CAA identifies 187

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7 Additional air pollutants such as VOCs and HAPs are regulated through other components of the CAA.
8 The current NAAQS are listed on USEPA's website at https://www.epa.gov/criteria-air-pollutants/naaqs-table.

pollutants as HAPs. Most HAPs are emitted by human activity, including motor vehicles, factories, refineries and power plants. Mercury is the HAP compound most associated with the burning of coal and power plant emissions. Other important issues concerning power plant emissions include acid deposition related to SO_2 and NO_x emissions, and visibility impairment, which, in the TVA region, is related mostly to ammonium sulfate particles formed from SO_2 emissions from coal-fired power plants. The most sensitive areas in the region are high elevation, forested areas such as the Great Smoky Mountains National Park. The nature of these pollutants, their effects, and their relationships to power production and industry are discussed more fully in TVA's 2019 IRP EIS.

Greenhouse gases (GHGs) occur in the atmosphere both naturally and as a result of human activities, such as the burning of fossil fuels. GHG emissions due to human activity are the primary cause of increased atmospheric concentration of GHGs since the industrial age and are the primary contributor to climate change. The primary GHGs are carbon dioxide (CO_2), methane, and nitrous oxide. GHGs are non-toxic and non-hazardous at normal ambient concentrations, and there are no applicable ambient air quality standards or emission limits for GHGs under the CAA. The primary greenhouse gas emitted by electric utilities is CO_2, produced by the combustion of coal, natural gas, and other fossil fuels. Under the 2019 IRP, TVA CO_2 emissions (measured by tons and by the emissions rate) resulting from the power generated by TVA and from non-TVA facilities marketed by TVA are anticipated to decline.

3.4 Water Resources

The quality of the region's water (surface water and groundwater) is critical to the protection of human health and aquatic life. Major watersheds in the TVA region include the entire Tennessee River basin, most of the Cumberland River basin, and portions of the lower Ohio, lower Mississippi, Green, Pearl, Tombigbee, and Coosa River basins. As described in detail in TVA's 2019 IRP EIS, these water resources provide habitat for aquatic life, recreational opportunities, domestic and industrial water supplies, navigation and other benefits. Wastewater discharges from cities or industries and runoff from nonpoint source activities such as construction, agriculture, mining, and air deposition can potentially degrade water quality.

Pollution involves the presence or introduction of a substance or object into water resources that may harm the water resource and impact its beneficial uses, such as swimming or aquatic life. Every two years, states are required to submit a report to the USEPA under Section 303(d) of the Clean Water Act. This report identifies the "impaired" lakes and streams that are not complying with water quality criteria and, consequently, are not suitable for their designated use(s). Thus, each state's 303(d) report provides an updated overview of assessed water quality in each state.

Sources of degraded water quality may include:

- Wastewater discharges from municipal sewage treatment systems, industrial facilities, concentrated animal feeding operations, and other sources;
- Runoff discharges from agriculture, forest management activities, urban uses, and mine lands, which transport sediment and other pollutants into streams and reservoirs. Runoff from commercial and industrial facilities and some construction sites is regulated through state National Pollutant Discharge Elimination System

(NPDES) storm water permitting programs. Sources not regulated through the NPDES program are referred to as “nonpoint source” runoff;

- Cooling systems, such as those used by electrical generating plants and other industrial facilities to withdraw water from streams or reservoirs, use it to cool facility operations, and then discharge the above ambient water into streams and reservoirs. Impacts can result from temperature changes, the trapping of organisms against intake screens, or sucking organisms through the facility cooling system. These water intakes and discharges are controlled through state-issued NPDES permits; and

- Air pollution in the form of airborne pollutants such as SO2, mercury and NOx being spread through rainfall and deposition.

- Man made impoundments such as dams, can cause low dissolved oxygen and other water quality issues in head and tail waters.

- Contamination of the bottom sediments of a stream from point or non-point source pollution can cause bioaccumulation of contaminant in fish tissue, which could lead to fish consumption advisories and compromise of species health, especially of bottom feeding/dwelling species.

Additional regulatory protections for water quality and the mechanisms of how power generation can affect water quality and aquatic life are discussed in detail in the TVA (2011) and TVA (2019b) EISs.

Groundwater refers to water located beneath the surface in rock formations known as aquifers. Eight major aquifers occur in the TVA region. Approximately half of the region has limited groundwater availability because of natural geo-hydrological conditions. More than 64 percent of the region’s residents rely totally, or in part, on groundwater for drinking water. More than 1.7 million residents (22 percent) in the region maintain individual household groundwater systems, usually a well. All areas in the Tennessee Valley region can generally supply enough water for at least domestic needs. For the most part, the groundwater quality is adequate to support existing water supply uses even though some minimal treatment, such as filtration and chlorination, is sometimes required. Generating facilities involving combined cycle combustion turbines often make use of groundwater for either cooling or reinjection of heated water.

3.5 Land Use

TVA provides wholesale and retail power to portions of a seven state region comprising 80,000 square miles. Major land uses in the TVA region include forestry, agriculture, and urban/suburban/industrial development. Regional land use is described in detail in the *2019 IRP EIS* (2019b). Of the non-federal land in the TVA region, about 12 percent is considered developed and 88 percent is considered rural.

TVA’s existing power plant reservations, excluding the hydroelectric plants associated with multi-purpose reservoirs, occupy about 25,000 acres. The actual disturbed acreage of these non-hydroelectric facilities is about 17,400 acres. Existing non-TVA generation facilities from which TVA purchases power under PPAs utilize an area of approximately 2,400 acres.

3.6 Production of Solid and Hazardous Waste

Residential, Commercial and Industrial Wastes

Residential and commercial wastes are usually generated in many diffusely located areas and handled at municipal solid waste landfills. Most municipalities and counties currently engage in long-range planning processes to ensure that adequate capacity is provided for solid wastes generated within their jurisdictions. Solid waste reduction and recycling is an important emphasis in most of these plans. For example, in the state of Tennessee, in 2017, Tennessee businesses, industries, citizens and others disposed of 17,045,462 tons of solid waste. Of this amount, 7,373,749 tons went to Class 1 landfills and 161,897 tons were recycled, reused, or diverted to other facilities. (TDEC 2019).

Tennessee, along with other states in the Valley, has also implemented a program for the collection and safe storage and disposal of household hazardous waste (HHW). The program collects and properly disposes of paint, flammable liquids, corrosives, oxidizers, batteries, and pesticides. Ninety-four counties in Tennessee have participated in the mobile collection service since it began in 1993, and an average event yielded 4,592 pounds of HHW (with a 0.6 percent participation rate). (TDEC 2015)

Industrial solid and hazardous waste generation and handling is similar. Current legislative and regulatory programs encourage and/or mandate the reduction, recycling, and proper disposal of industrial solid and hazardous wastes. The states within the TVA PSA have state-administered Resource Conservation and Recovery Act (RCRA) equivalent programs, which emphasize waste reduction, recycling, and proper handling and disposal of solid and hazardous wastes. Industries benefit both financially and from a public relations standpoint by engaging in waste reduction and recycling opportunities in the same way that TVA benefits from its marketing and utilization of coal combustion residuals (CCR) that are a by-product of coal-based generation. It is, therefore, likely that industrial solid and hazardous waste generation and disposal will continue to decline in the future.

Disposal of solar equipment at the end of its useful life could also result in solid and hazardous waste. Solar panels can be recycled, but recycling is currently not widely available in the U.S. (Marsh 2018). However, options for recycling solar panels are expected to increase as the overall market expands and currently deployed panels near the end of their expected lives. If recycling is not available, solar panels often end up in landfills. According to Tao and Yu (2015), recycling of typical PV solar panels lacked strong economic rationale during the first half of the present decade.

The impacts of solar equipment disposal, especially improper disposal, have been widely noted in various literature (Aman et al., 2015; Paiano, 2015). In a detailed report on global waste from solar systems, Weckend et al. (2016) estimate that the U.S. will generate a cumulative 7.5 million to 10 million tons of solar equipment waste by 2050, making the U.S. the second greatest producer of solar waste after China. Weckend et al. (2016) also estimate that by 2050, global annual waste from solar panels alone could exceed 10% of the total global electronic waste produced in recent years.

According to Weckend et al. (2016), only the European Union (EU) has enacted waste regulations specific to solar panels. In other countries, like the U.S., solar panels are typically treated as general waste or industrial waste. According to this same report, the most common type of solar panels produced globally are based on crystalline silicon (c-Si) technology. These panels are composed primarily of glass, aluminum, silicon, polymer, and copper.

An alternative solar panel technology that is currently less common is termed thin-film Cadmium Telluride (Cd-Te), which is composed primarily of glass and polymer (Weckend et al. 2016). In addition, these panels contain small amounts of cadmium compounds, which are potentially harmful to human health if leached from landfills. Cyrs et al. (2014) assessed the potential human health burden from these panels in landfills and determined that they did not likely present a material risk given current levels of solar adoption.

Additional sources of waste related to private-scale solar systems include panel mounting and racking systems, which are typically composed of aluminum and steel. A smaller total quantity of waste may also be produced from end-of-life electrical inverters and stationary batteries.

TVA-Generated Wastes

Types of wastes typically produced by construction activities, whether by TVA or others, include vegetation, demolition debris, oily debris, packing materials, scrap lumber, and domestic wastes or garbage. Non-hazardous wastes (excluding CCR) typically produced by common operation of TVA facilities include sludge and demineralizers from water treatment plant operations, personal protective equipment, oils and lubricants, spent resins, desiccants, batteries, and domestic waste. In 2016, TVA facilities produced approximately 23,000 tons of non-hazardous solid waste per year; this quantity decreased to approximately 18,750 tons in 2017 (TVA 2019b).

TVA facilities include large, small, and very small quantity generators (previously conditionally exempt generators) of hazardous waste. Hazardous non-radiological wastes typically produced by common TVA facility operations include paint and paint solvents, paint thinners, discarded out-of-date chemicals, parts washer liquids, sand blast grit, chemical waste from cleaning operations, and broken fluorescent bulbs. Routine operations between 2015 and 2017created an average of 9.49 tons of hazardous waste. In 2017, approximately 27.4 tons of universal waste was generated and recycled by TVA (TVA 2019b). TVA's hazardous wastes and those requiring special handling (TSCA and universal waste) are generally shipped to Waste Management's Emelle, Alabama facility for disposal. TVA programs for reducing hazardous waste, based upon source reduction, have been in place for some time.

Coal combustion solid wastes or residues (i.e. CCRs) include fly ash, bottom ash, boiler slag, char spent bed material, and sludge from operation of wet flue gas desulfurization systems. In the past, the USEPA determined that CCRs are not hazardous, and in April 2015 the USEPA decided to continue to regulate them as non-hazardous, solid waste. In 2015, TVA produced approximately 3.9 million tons of CCRs, of which 33.6 percent was utilized or marketed (TVA 2016). Annually, CCR production at TVA's coal-fired plants fluctuates due to a variety of factors including: plant planned and forced maintenance outages, load swings, plant dispatch (the process by which plants are directed to increase or decrease power generation based on the cost of production at each plant—generally the larger, more efficient units run more and the smaller, less efficient units run less), and variation in fuel supplies (BTU, sulfur, and ash content of the fuels burned). Additionally, recent decisions to retire coal-fired generation further reduce the amount of CCRs generated by TVA at its plants. The amount of CCRs that are disposed of is also reduced through marketing and utilization of these by-products in a number of commercial applications including the use of fly ash in concrete products, bottom ash as aggregate in cement block manufacturing, boiler slag for roofing granules and industrial abrasives, and scrubber gypsum in gypsum wallboard and cement manufacturing.

CHAPTER 4 – ENVIRONMENTAL CONSEQUENCES

This section includes the analysis of the potential environmental and socioeconomic effects of the three alternatives. An analysis of taking no action (Alternative A) is also provided to establish a baseline for comparison among alternatives.

4.1 Energy Production and Use

4.1.1 Alternative A – No Action Alternative (GPP Program Continues)

Under Alternative A, the GPP Program would generally continue as it was implemented in 2019. The price at which TVA purchases energy from EUCs would continue to be $0.09/kWh for Residential/GSA-1 systems under 10 kW, and $0.075/kWh for Residential/GSA-1 systems over 10 kW and non GSA-1 Commercial Customers. The purchase agreements would continue to be for a 20-year term. The annual capacity of new enrollments would be capped at 10 MW, a slight increase from 2019. In 2018, the annual enrollment cap was 10 MW and only 2.5 was reserved; the remaining 7.5 MW was carried over into 2019. An annual enrollment cap of 10 MW is assumed starting in 2020.

The potential future enrollment in GPP under Alternative A is projected using several methods to account for potential uncertainty. First, an upper bound scenario is developed based on the maximum potential enrollment. Second, a simple forecast based on extending recent trends is calculated. Third, an economic forecast is based on the potential financial decisions that households and businesses could face in future years when considering among the three alternatives of installing a system with GPP enrollment, installing BTM, or neither.

4.1.1.1 Upper Bound Scenario

Because of the annual capacity limit, the maximum amount of capacity from GPP projects that could be added from 2019 through 2038 is 197.5 MW (Figure 4-1).[9] For comparison, the total firm summer capacity in 2038 in the TVA PSA is projected to be over 39,900 MW (TVA 2019a, Figure G-1.) Thus, the maximum GPP participation in 2038 would comprise less than 0.5 percent of the total TVA capacity.[10] Renewable energy is projected to account for about 8,400 MW of the 2038 capacity, approximately 21 percent of the total. The maximum GPP capacity in 2038 would be approximately 2.4 percent of the capacity from renewable sources in 2038. These comparisons are based on the highest amount of new GPP capacity during the planning period, which would runs through 2038.[11] The percentages in 2019 would be near zero and would increase through 2038 as additional capacity is added each year.

[9] The annual capacity limit would be 7.5 MW in 2019 and 10 MW thereafter. 19 years x 10 MW per year + 1 year x 7.5 MW per year = 197.5 MW.

[10] 197.5 MW ÷ 39,900 MW x 100 = 0.49%.

[11] This comparison is also conservative (likely to overstate potential impacts) because the GPP Program's non-firm capacity is compared to system-wide firm capacity, and firm capacity is higher than non-firm capacity.

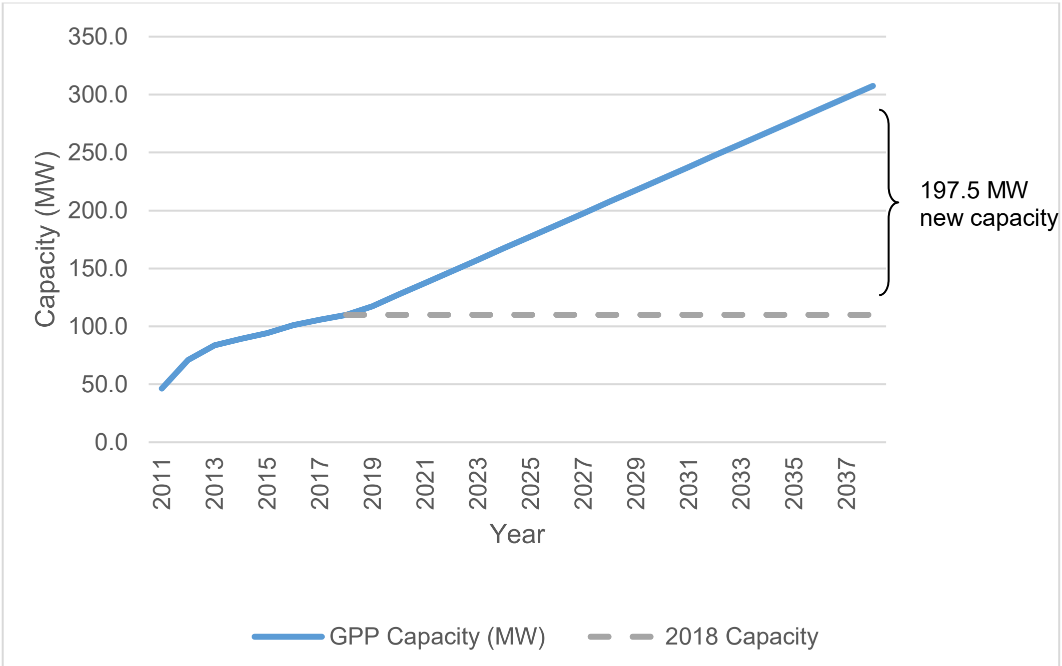

Figure 4-1. GPP Capacity in the Upper Bound Scenario

Because energy generation systems operate below full capacity, considering energy generation serves as a better basis than capacity for analyzing the potential environmental impacts that may result from growth. Most GPP installations in the last few years have been solar. Because of this and the fact that the cost of solar systems is expected to decrease in the upcoming years (see TVA 2019a), TVA assumes for the purposes of this analysis that all future GPP enrollment would be private-scale solar systems. Over an entire year, solar systems generate electricity at a much lower average rate than the maximum capacity, largely because the panels operate at maximum capacity only during optimal atmospheric conditions.[12]

Consistent with assumptions in the 2019 IRP, this analysis assumes that private-scale residential solar systems operate at an average of 15.5 percent of maximum capacity over the course of a year and private-scale commercial systems operate at an average of 19.0 percent of maximum capacity over the course of a year. There are 8,766 hours in an average year.[13] Each 1 MW of private-scale residential solar capacity will generate about 1,400 MWh of energy in one year,[14] and each 1 MW of private-scale commercial solar capacity will generate about 1,700 MWh of energy in one year.[15] About 75 percent of the current GPP capacity is commercial. Assuming that this percentage applies in the future, the weighted-average energy produced per 1 MW of future GPP solar capacity is about

[12] Optimal conditions generally occur during direct sunlight in the late spring. During other times of year and during cloudy conditions, the panels will produce far less electricity than rated capacity.
[13] 365.25 days per year x 24 hours per day.
[14] 1 MW capacity x 15.5% capacity factor x 8,766 hours = 1,358.73 MWh.
[15] 1 MW capacity x 19.0% capacity factor x 8,766 hours = 1,665.54 MWh.

1,600 MWh.[16] Applying this to maximum future GPP capacity of 197.5 MW, the maximum energy generated in 2038 would be about 316,000 MWh.[17]

For context, the TVA system delivered 163 million MWh of electricity in FY2018 (TVA 2019a), of which about 13 percent was from renewable sources (hydro, wind, solar, and biomass). Thus, the upper bound projection equates to 0.2 percent of TVA's total generation and 1.5 percent of the renewable generation in FY2018.

The percentages based on energy generation are lower than those for capacity because solar generates less electricity per unit of capacity over the course of a year than other generation technologies (Table 4-1). This concept is often referred to as capacity factor, which is the percent of electricity generated over a time increment (typically one year) divided by the maximum electricity generation possible over that same time increment based on rated power capacity. The differences in capacity factors across types of generation reflect both the physical systems and the way that they are utilized.

Because nuclear has the highest capacity factor, nuclear facilities are used as the "base load", meaning that it is typically run when not undergoing maintenance. Coal and natural gas are both turned on and off as needed, adjusting to varying generation of renewables as well as varying load based on customer demand. Renewables are generally used as much as possible; however, the availability varies over time depending on factors such as precipitation and river flows, wind speed, and solar intensity. While hydroelectric and wind have capacity factors comparable to coal and natural gas, solar has the lowest capacity factor of all the technologies.

Table 4-1. Comparison of Capacity Factors for Generation Sources in the TVA PSA

Type of Generation	FY2018 Capacity (MW)[a]	Max Generation at 100% Capacity (GWh)[b]	FY2018 Energy Generation (GWh)[c]	FY2018 Capacity Factor[d]
Nuclear	7,700	67,498	64,194	95.1%
Coal	7,900	69,251	34,026	49.1%
Natural Gas	12,500	109,575	43,481	39.7%
Hydroelectric	4,200	36,817	16,399	44.5%
Wind	1,227	10,756	4,055	37.7%
Solar	371[e]	3,252	491	15.1%
Total	**33,898**	**297,150**	**162,646**	**54.7%**

[a] From TVA 2019(a), Section 5.2.1
[b] Capacity (MW) x 365.25 days per year x 24 hours per day.
[c] From TVA 2019(a), Integrated Resource Plan Volume I – Final Resource Plan
[d] FY2018 Energy Generation ÷ Max Generation at 100% Capacity.
[e] Includes 1 MW of TVA-owned capacity and 370 MW of programs and long-term purchased power contracts, including the GPP.

[16] 0.75 x 1,665.54 MWh + 0.25 x 1,358.73 MWh = 1,588.84.
[17] 1,588.84 MWh/MW x 197.5 MW = 316,000 MWh.

4.1.1.2 Projection 1: Extension of Current Trends

The maximum capacity and energy generation discussed above is unlikely, as new GPP enrollments have decreased in recent years and have been well below the maximum capacity limits. Another method of projecting future GPP enrollment is to extend recent trends.

Trend lines were fitted to recent GPP enrollment data and used to forecast future GPP participation (Figure 4-2 and Figure 4-3). This method suggests that both new GPP systems and new GPP capacity coming online would decline to zero around 2025 if recent trends continued. Note that this method is simplistic in that it does not account for changing financial values faced by EUCs or variables that affect GPP participation over time; it simply assumes that recent trends would continue. This method implicitly assumes that GPP payments would continue to decline, although they would likely be held constant at the 2019 levels. Therefore, the trend lines may understate future new enrollment.

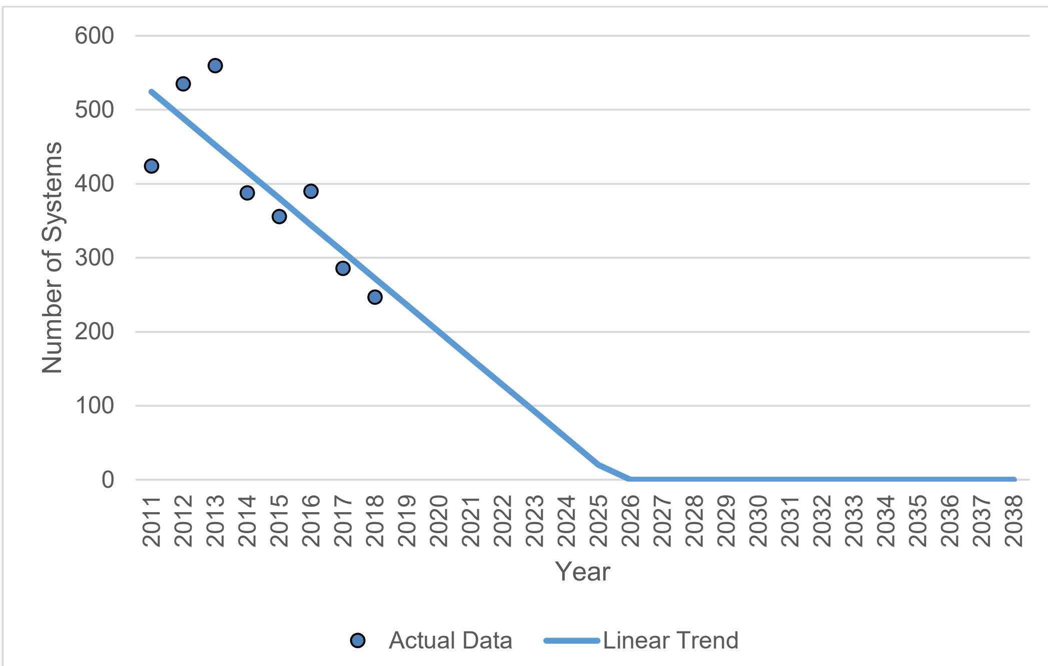

Figure 4-2. Forecast of New GPP Systems Coming Online

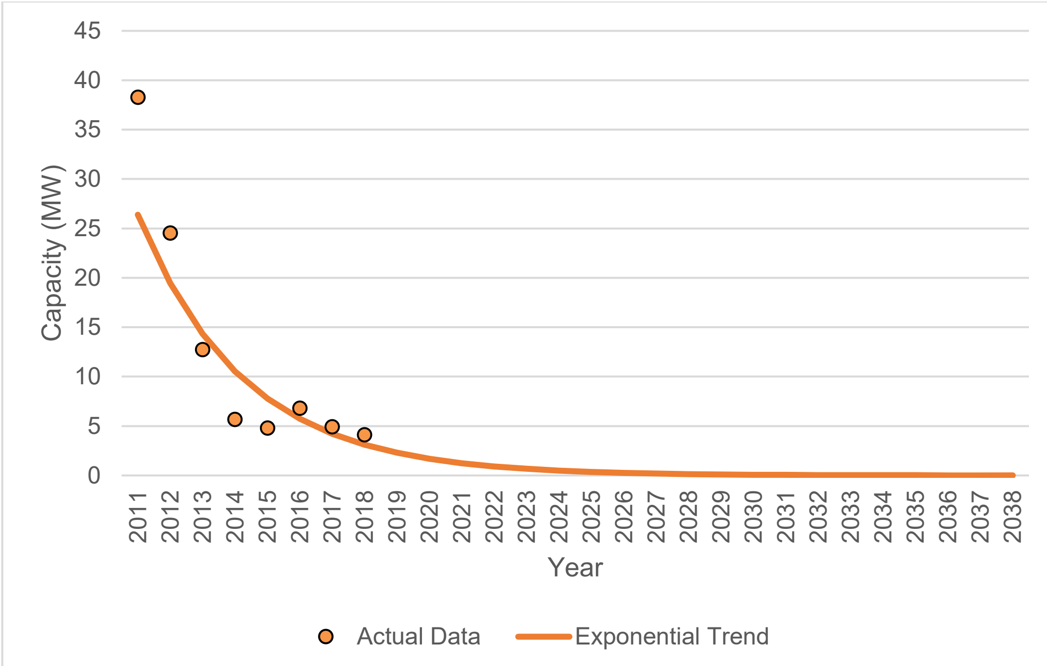

Figure 4-3. Forecast of New GPP Capacity Coming Online

4.1.1.3 Projection 2: Behavioral Modeling

Another method to project the potential maximum GPP growth over time, under Alternative A, is based on behavioral modeling of residential and commercial EUCs' financial decisions. These projections also incorporate expected future changes in the main variables that inform these decisions, such as the future energy prices and costs of private-scale system installation. The financial decision considers three mutually exclusive options: a) install a private-scale solar system and enroll in GPP; b) install a private-scale solar system as BTM; or c) do not install a private-scale solar system.

The projections occur in three main steps:

1. An adoption rate curve, which forecasts increasing adoption in private-scale solar from 2018 levels, is forecast for each year from 2019-2038. The adoption rate curve assumes that all other factors, such as solar installation costs, are constant over time. The remaining steps adjust the adoption curve to account for the expected changes in important financial factors over time.

2. The "simple payback period", a common metric for evaluating the length of time in years it takes for a solar project investment to pay for itself with future financial savings, and is calculated based on projected values over time of variables that affect the payback period, such as solar installation costs and the GPP energy credit.

3. The maximum market share, which is the maximum percentage of residential and commercial buildings that are suitable for adopting private-scale solar, is calculated based on the payback period. The maximum market share equation is based on a published relationship between solar adoption and the payback period. The

maximum market share is used to adjust the result of (1) over time to account for variables that affect the financial outlook of GPP and BTM investment.

The adoption rate curve and maximum market share come from a National Renewable Energy Laboratory publication (Denholm, Drury, and Margolis 2009) and were used in the TVA 2019 IRP modeling. Each step in the projections is summarized in the following sections.

Adoption Rate Curve

The adoption rate curve models the adoption rate of new technologies as an S-shaped curve. This reflects that fact that technology adoption rates are typically relatively slow soon after a technology is available, increase relatively rapidly over time as the technology becomes more familiar, and then slow as the market becomes saturated, meaning that most people who will adopt the technology have done so.

The NREL report uses 2001 as the year that private-scale solar was widely available at the national level. TVA uses 2003, the beginning of the GP/GPP Program, as this date.[18] The resulting curve (Figure 4-4) predicts that private-scale solar adoption would increase fairly rapidly from 2019 through 2029 and would slow thereafter, reaching close to the maximum adoption by 2038. Note that the percentage in the maximum adoption rate is calculated out of the number of EUCs that would install solar, not the total number of households that could install solar. Thus, the curve does not imply that 100% of EUCs would have installed solar by 2038.

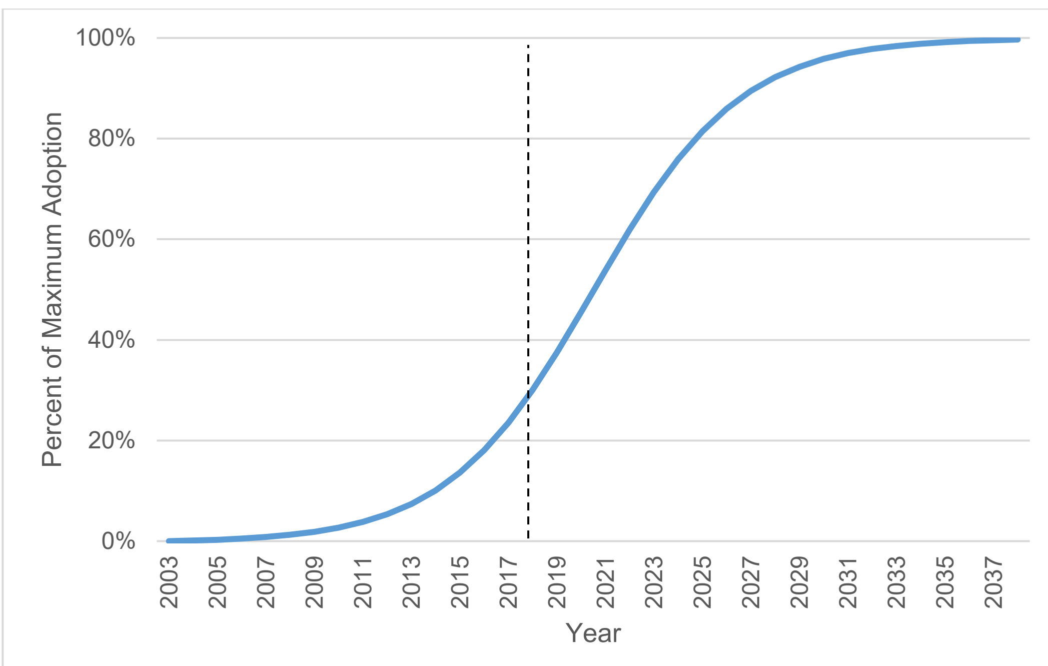

Figure 4-4. Adoption Rate Curve used in Projections

[18] The adoption rate curve requires two other parameters, p and q. Consistent with the 2019 IRP modeling, we use p=0.001 and q=0.33.

Payback Period

The payback period is used in two ways in the projections. First, it is used as a proxy for whether or not a private-scale solar system is a viable investment. Second, it is used as an input into the maximum market share equation.

From an economic standpoint, a private-scale solar system is considered a viable investment if the total financial benefits of the system are less than its total cost. The simple payback period, or the number of years that is required for a system to "break even" (i.e., when the benefits equal or exceed the costs) is often used as a way to simplify the economic calculation. [19] If the simple payback period is less than the useful life of the system, then the system is considered a viable financial investment.

For GPP-enrolled systems, financial benefits are accrued for 20 to 30 years, depending on decisions EUCs make after the 20-year PA with TVA expires.[20] The payback period is then the number of years required for the total energy credit payments to equal or exceed the initial installation costs plus any expected operation and maintenance (O&M) costs that may occur. If the payback period is less than 20 years, GPP enrollment is a viable financial investment. If the payback period is between 20 and 30 years, GPP may be a viable investment depending on the EUC's decision at the end of the PA.

A BTM system will accrue financial benefits over its useful life in the form of reduced energy consumption and bills from an LPC. The useful life is assumed to be 30 years based on 2019 IRP modeling. If the payback period is less than 30 years, then the system is a viable financial investment. The simple payback period indicates that residential EUCs who install a typical solar system at recent prices will experience monetary savings (compared to not having a solar system) during the second half of the useful life of the system. Figure 4-5 illustrates the amount of savings for a solar system for a typical BTM residential system at current costs.[21]

The average initial expenditure for a private-scale solar system is about $13,000, meaning that the EUC has negative savings of $13,000 in the year the system is installed. Each year after installation, the EUC spends money on O&M and saves money on electric bills (they use energy produced by the system, which reduces the amount of energy they purchase from their LPC). Net savings of about $740 per year accumulate over time. The payback period, when the total net savings equals $0, is almost 18 years. For the remaining 12 years of the system's useful life, savings are positive each year and accumulate over time. At the end of the system's useful life, the cumulative savings over the entire 30-year life of the system are approximately $9,000. Thus, the initial expenditure of $13,000 results in a net savings of $9,000 over 30 years.

[19] The "simple payback period" ignores some valid economic considerations, such as a discount rate, and is commonly used because of its simplicity. For example, many online solar investment calculators use the simple payback period. See Drury et al. 2011 for discussion of different metrics used to evaluate the financial viability of solar investments.

[20] EUCs have three main choices after the PA expires: 1) let the system continue to operate and send energy to the grid and receive no energy credit from TVA; 2) uninstall the system after 20 years; or 3) convert the system to BTM for the remainder of its useful life.

[21] This assumes a 6 kW capacity system with a cost of about $3,000/kW and an ITC of 30%.

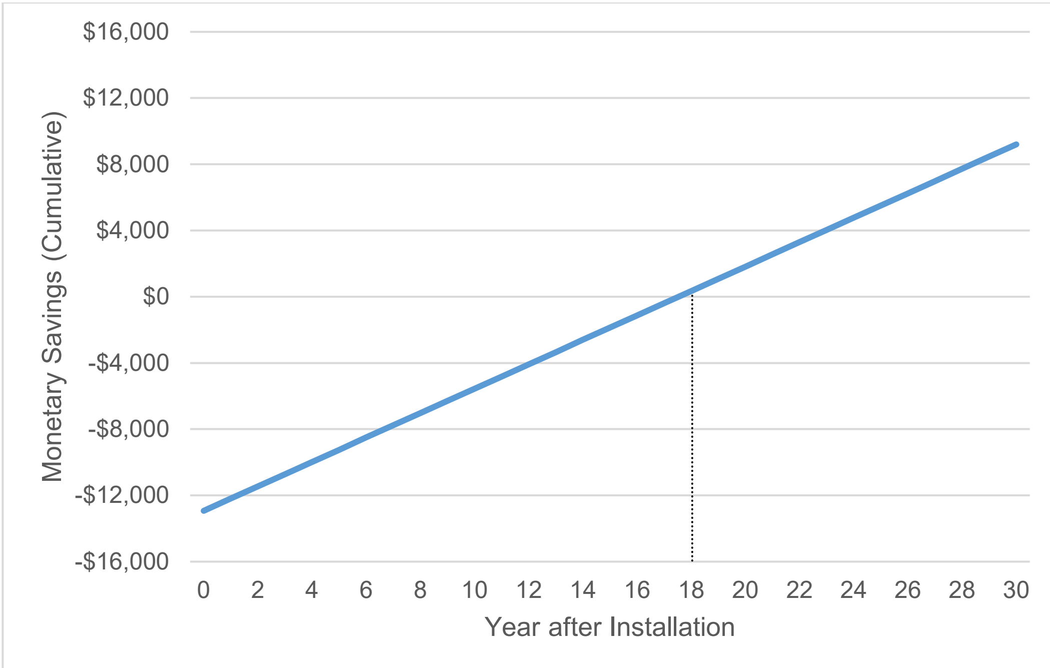

Figure 4-5. Monetary Savings over the Useful Life of a Typical Private-scale BTM Solar System

This example illustrates the importance of the payback period. Lower payback periods result in earlier systems break even times and more years of monetary savings. All else equal, more EUCs are expected to adopt private-scale solar systems when the payback period is lower.

The payback period for a private-scale solar BTM installation depends on several variables:

- The initial cost of the system (higher increases the payback period);
- The Federal Investment Tax Credit (ITC) (higher decreases the payback period);
- A capacity factor, which is the average amount of energy that can actually be generated measured as a proportion of the system's maximum capacity (higher decreases the payback period);
- A utilization factor, which is the proportion of energy possibly generated that an EUC actually self-consumes coincident with generation (higher decreases the payback period);
- The per unit rate the EUC is charged for electricity (higher decreases the payback period); and
- Annual O&M (higher increases the payback period).

The decision to install a GPP-enrolled system versus a BTM system is influenced by two main factors. First, a GPP system sends energy to the grid any time it is generating energy,

which does not depend on simultaneous energy demand by the EUC as BTM does. Therefore, the utilization factor is not included in determining the payback period for GPP systems.[22] Second, GPP does not reduce the amount of energy the EUC purchases from the grid as does a BTM system. Instead, a GPP system receives a monetary payment for the energy sent to the grid, called an energy credit.

The current modeling calculates the payback periods for four EUC and system combinations: GPP and BTM systems and residential and commercial EUCs. These four groups are modeled separately because they have different costs, energy rates, and differing ITC levels over time.

Table 4-2 through Table 4-4 contain the main assumptions of the modeling. Importantly:

- Commercial systems have higher capacity and utilization factors, lower costs (per kw), and higher a ITC than residential systems after 2021 (all tend to decrease payback period relative to residential systems);
- Commercial systems have a lower GPP energy credit and a lower retail energy rate than residential systems (both tend to increase payback periods relative to residential systems);
- The installation costs for both commercial and residential systems are projected to decrease over time (tends to decrease future payback periods);
- The ITC for both commercial and residential systems are projected to decrease over time (tends to increase future payback periods); and
- Retail energy rates are projected to increase (tends to decrease payback periods for BTM installations).

Table 4-2. Assumptions for Variables that do not Change over Time

Variable	Value
Residential Capacity Factor	0.155
Commercial Capacity Factor	0.190
Residential Utilization Factor (BTM only)	0.6
Commercial Utilization Factor (BTM only)	0.8
Residential GPP Energy Credit (GPP only)	$0.09 / kWh
Commercial GPP Energy Credit (GPP only)	$0.075 / kWh
Residential Annual O&M	$21 / kW
Commercial O&M	$15 / kW

GPP energy credits are discussed in Section 2.1.1.
The utilization factor is an estimate based upon the TVA's Solar Calculator FAQs (TVA 2019d) and from McKenna et al. (2018).
All other variables are taken from the 2019 IRP solar modeling.

[22] As all of the energy generated goes to the grid, the utilization factor essentially is equal to 1.

Table 4-3. Assumptions for Variables that Change over Time (Residential EUCs, applies to GPP and BTM systems)

Year	Solar Install Costs ($/kW$_{DC}$)	ITC (Percentage)	Retail Energy Rate ($/kWh)
2019	3,079	30	0.106
2020	2,985	26	0.106
2021	2,896	22	0.106
2022	2,811	0	0.107
2023	2,729	0	0.107
2024	2,671	0	0.109
2025	2,620	0	0.109
2026	2,573	0	0.110
2027	2,529	0	0.111
2028	2,489	0	0.112
2029	2,450	0	0.113
2030	2,412	0	0.114
2031	2,376	0	0.114
2032	2,341	0	0.114
2033	2,308	0	0.115
2034	2,278	0	0.116
2035	2,249	0	0.116
2036	2,221	0	0.116
2037	2,195	0	0.116
2038	2,170	0	0.117

All variables are from the 2019 IRP solar modeling.

Table 4-4. Assumptions for Variables that Change over Time (Commercial EUCs, applies to GPP and BTM systems)

Year	Solar Install Costs ($/kW$_{DC}$)	ITC (Percentage)	Retail Energy Rate ($/kWh)
2019	2,004	30	0.104
2020	1,939	26	0.104
2021	1,876	22	0.104
2022	1,816	10	0.105
2023	1,758	10	0.106
2024	1,714	10	0.107
2025	1,674	10	0.107
2026	1,638	10	0.108
2027	1,605	10	0.109
2028	1,573	10	0.110
2029	1,542	10	0.111
2030	1,513	10	0.112
2031	1,485	10	0.112
2032	1,457	10	0.112
2033	1,430	10	0.113
2034	1,406	10	0.114
2035	1,382	10	0.114
2036	1,359	10	0.114
2037	1,337	10	0.114
2038	1,316	10	0.115

All variables are from the 2019 IRP solar modeling. All dollars are inflation-adjusted.

The projected payback periods for GPP and BTM are shown in Figure 4-6 below. While GPP systems had lower payback periods in the past due to higher GPP energy credits, GPP systems have higher payback periods in all future years. Residential systems generally have higher payback periods than commercial systems in the future.

Based solely on these payback periods, little investment in residential private-scale solar is expected, as payback periods for both GPP and BTM systems are generally above their respective useful life periods (20 years for GPP and 30 years for BTM). This is consistent with the findings of Projection 1, Extension of Current Trends, for GPP systems. It is also consistent with the 2019 IRP modeling, which finds that most future private-scale solar capacity would be commercial rather than residential. However, some residential EUCs likely install solar systems for reasons other than pure financial return, such as environmental concerns and the ability to rely on self-generated energy. Therefore, some residential EUCs may adopt private-scale solar even if the payback period suggests the financial costs may not be fully recovered. Another factor to consider is that these payback periods are calculated assuming typical input variables; however, some EUCs may have different input variables and therefore have a different financial outlook. The economic projections do not limit future projections under the assumption that EUCs consider only financial benefits. Therefore, future residential investment is projected. As shown in

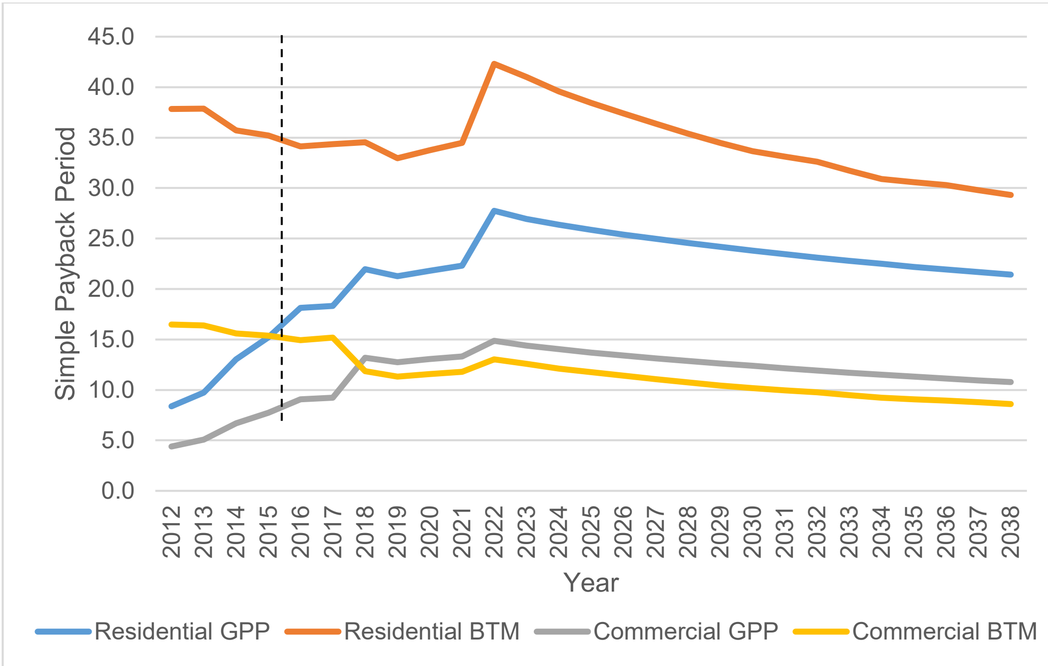

Figure 4-6. Projected Private-Scale Solar System Payback Periods

Section 4.1.1.4, this provides an intermediate projection between the Upper Bound Scenario (Projection 1) and the extension of recent trends (Projection 2).

Future commercial GPP and BTM systems are both viable investments in terms of the simple payback period occurring prior to the end of expected system useful life. Based on the payback periods, BTM is a slightly better investment in all future years. Commercial EUCs likely have multiple considerations when deciding whether to install solar, including the potential financial return compared to other investments, public relations value of self-generation, etc. In addition, commercial EUCs may undertake more detailed financial calculations than the simple payback period. Therefore, these projections should be considered a useful simplification for the purposes of this analysis.

<u>Maximum Market Share</u>

The PV technical potential refers to the maximum proportion of EUCs with suitable buildings or land that adopt GPP or BTM systems. The maximum market share is the proportion of the PV technical potential, which is economically viable based on the payback period. The maximum market share is estimated using the equation described in the 2019 IRP (see illustration in TVA 2019a, Figure C-6):

$$Maximum\ Market\ Share = e^{-0.3 \times Payback\ Period}.$$

This equation predicts a maximum market share of about 75 percent for a 1-year payback period and a maximum market share of about 0.25 percent for a 20-year payback period.

<u>Using the Maximum Market Share to Adjust the Adoption Rate Curve</u>

The final step is to combine the adoption rate curve and the maximum market share. Changes in the maximum market share each year were used to adjust the adoption rate curve accordingly. In other words, if the maximum market share decreased by 5 percent

from one year to the next, the adoption rate in the second year would be adjusted downward by 5 percent. Starting with the 2018 known amounts of private-scale solar capacity, the adjusted adoption rate curve was used to project capacity from 2019 through 2038 (Figure 4-7).

The overall shape of future private-scale solar deployment is driven by the adjusted adoption rate curve. The allocation across the four categories depends on both the starting amounts in 2018 and the maximum market shares, which depend on the different payback periods over time. As of 2018, GPP capacity was about 110 MW, and about 75 percent of that was commercial. TVA found that known BTM solar in 2018 was about 37 MW (TVA 2018).[23] The total private-scale solar capacity is projected to be 365 MW by 2038, of which 240 MW is enrolled in GPP. This is a total increase over current capacity of 130 MW.

The annual additions to GPP capacity are projected to be at the capacity limit of 10 MW for almost 10 years and then decrease. This is largely a function of the increasing adoption rate curve, which outweighs the effect of the increasing payback period.

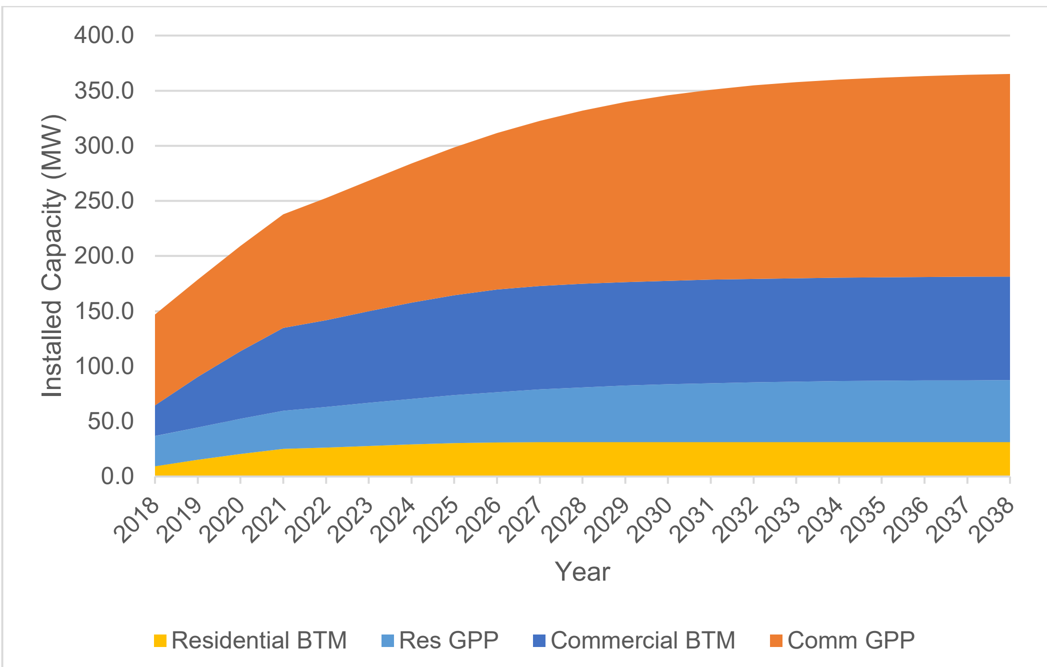

Figure 4-7. Projected Private-Scale Solar Capacity

[23] TVA does not have complete information on BTM systems. Therefore, the actual amount in 2018 could be higher.

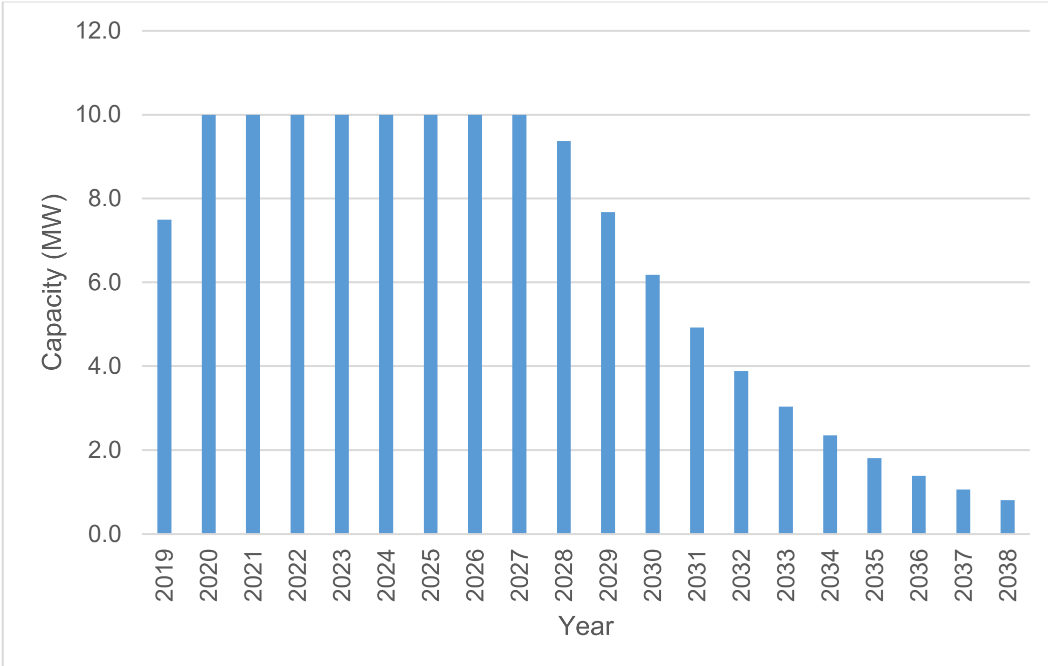

Figure 4-8. Projected New GPP Capacity Coming Online

4.1.1.4 Summary of Private-Scale Solar Projections under Alternative A

The preceding sections summarize three methods used to project future GPP capacity under Alternative A, the No Action Alternative. First, the upper bound scenario calculates the maximum possible amount of GPP participation from 2019 through 2038. Projection 1 extended recent GPP enrollment trends and found that new GPP enrollment would continue to decline to zero within 10 years. Projection 2 modeled a behavioral decision based on financial considerations (summarized as the simple payback period) and changing adoption rates over time. Projection 2 suggests that new GPP enrollment would increase over the first 10 years of the forecast and would decline in the second 10 years. Based solely on the payback period estimated in Projection 2, and ignoring the adoption rate curve, there would be little or no future GPP enrollment, which is similar to the result of Projection 1.

Considering all of the available information, our best estimate is the average of Projections 1 and 2. The best estimate projects that new GPP enrollment will be similar to recent levels for about 10 years and then will decrease over the next 10 years. The results of the projections for Alternative A are presented in Figure 4-9 (new annual capacity) and Figure 4-10 (new cumulative capacity).

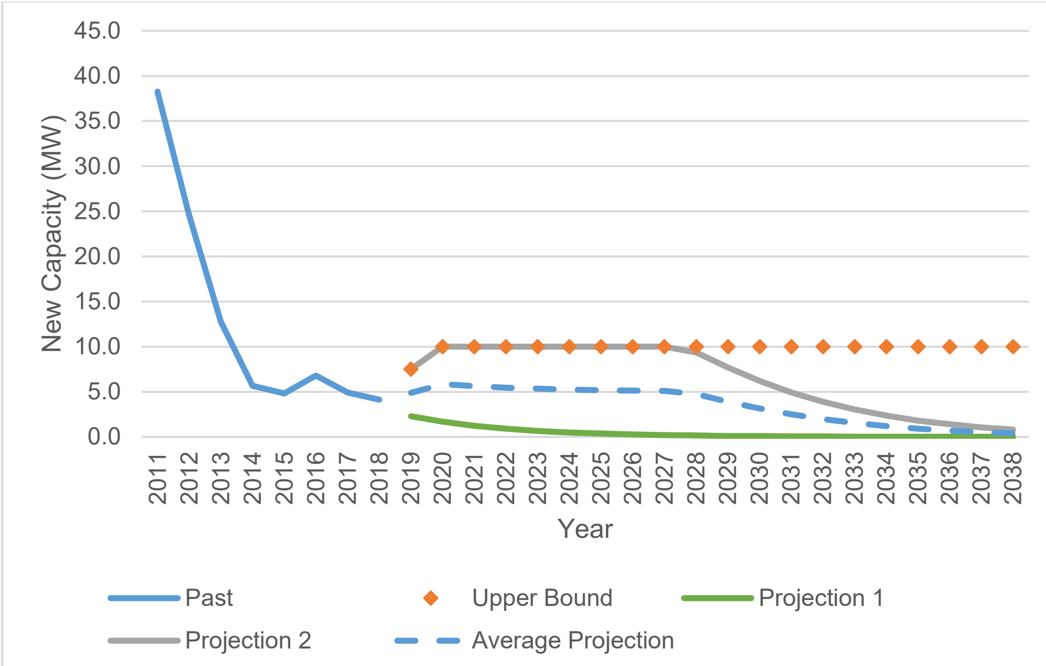

Figure 4-9. Forecast Annual New GPP Capacity

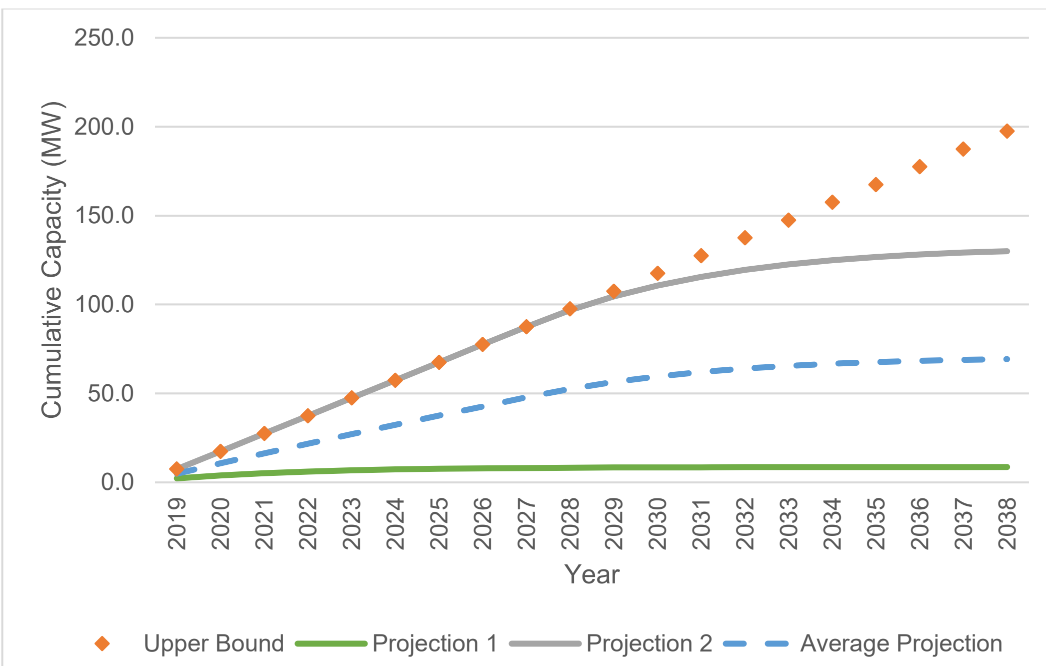

Figure 4-10. Forecast Cumulative New GPP Capacity, starting in 2019

It is important to place these GPP projections into context. As the GPP Program is offered throughout the entire TVA PSA, the TVA PSA is the most relevant context for considering

the potential magnitudes of these projections. Table 4-5 and 4-6 compare the results of the projections to the 2018 renewable and total energy capacity and energy generation in the TVA PSA. The proportions are small compared to the TVA PSA system totals. Continuation of the GPP Program is considered to have minor changes on the total energy generation and renewable to non-renewable mix in the TVA PSA. However, there would be no discernable changes in TVA operations.

Table 4-5. Comparison of Projected Future GPP Capacity to TVA PSA Capacity

Projection Scenario	Cumulative New GPP Capacity, 2019 through 2038 (MW)	Proportion of Renewable Capacity[b]	Proportion of Total Capacity[c]
Upper Bound	197.5	2.35%	0.49%
Projection 1	8.7	0.10%	0.02%
Projection 2	130.0	1.55%	0.33%
Average Projection (Best Estimate)[d]	**69.3**	**0.83%**	**0.17%**

[a] Capacity for the entire TVA PSA in 2018.
[b] Renewable capacity in 2018 was approximately 8,400 MW.
[c] Total capacity in 2018 was approximately 39,900 MW.
[d] Average calculated over Projections 1 and 2. Does not include the upper bound scenario.

Table 4-6. Comparison of Projected Future GPP Energy Generation to TVA PSA Generation

Projection Scenario	Energy Generation in 2038 (GWh)	Proportion of Renewable Energy Generation[b]	Proportion of Total Energy Generation[c]
Upper Bound	313.8	1.48%	0.19%
Projection 1	13.8	0.07%	0.01%
Projection 2	206.6	0.98%	0.13%
Average Projection (Best Estimate)[d]	**110.2**	**0.52%**	**0.07%**

[a] Generation for the entire TVA PSA in 2018.
[b] Renewable generation in 2018 was approximately 21,144 GWh.
[c] Total generation in 2018 was approximately 162,646 GWh.
[d] Average calculated over Projections 1 and 2. Does not include the upper bound scenario.

4.1.2 Alternative B – Discontinue GPP without Replacement Program

In Alternative B, the GPP Program would be discontinued at the end of 2019. This would not affect existing GPP customers, and the current GPP capacity of 110 MW would decrease to 0 MW by the end of 2039 as all 20-year purchase agreements that began through the end of 2019 would expire. The current capacity, except for 2019, was known and included in the 2019 IRP. Therefore, there would be no future changes to TVA's energy generation plans because of current GPP customers.

It is likely that many of the potential EUCs who would enroll in GPP under Alternative A would install a BTM system if the GPP Program was not available. Both involve installing a

private-scale solar system and getting some reduction in energy bills.[24] BTM and GPP typically involve similar systems (other than the metering connection), and the two systems would be similarly attractive to customers who are interested in installing solar for environmental and/or self-sufficiency reasons.

In this document, the behavioral modeling projections (Projection 2), included BTM.[25] These projections estimated that BTM capacity would be 125 MW in 2038. However, these projections depended on the 2018 levels of BTM, which are only partially known (TVA 2018). TVA does not have complete information on current levels of BTM in the TVA PSA, and the 2018 estimate of known BTM solar (37 MW) may be significantly understated. The 2019 IRP projection uses a different method to project future BTM, which is based on the total potential solar capacity technically suitable for BTM and is independent of the current amount of BTM capacity. The IRP projects there to be about 1,500 MW of BTM solar capacity in 2038, about 90 percent of which would be commercial and 10 percent would be residential. This suggests that the potential BTM capacity could accommodate an extra 69.3 MW, if all GPP enrollees under Alternative A chose to install BTM under Alternative B.

All else equal, if not all GPP capacity under Alternative A shifts to BTM under Alternative B, then TVA would have to increase its energy generation to cover the shortfall. As discussed in Section 4.1.1, the amounts of energy associated with future GPP enrollment under Alternative A are very small compared to energy generation in the TVA PSA. Absorbing any energy generation lost from GPP Program discontinuation would result in no discernable changes to TVA operations and would require a minor change in the renewable to non-renewable energy mix in the TVA PSA. This change is well within the range of expected uncertainty (see TVA 2019a for discussion of uncertainty in future energy supply and demand).

4.1.3 Alternative C – Discontinue GPP Program and Present New Offering

Alternative C would discontinue new GPP enrollments at the end of 2019 and would offer a new private-scale service program designed to better reflects customers' needs (see Section 2.1.3). For the purpose of this assessment, TVA assumes that all LPCs that currently participate in GPP will elect to make this offering available to their EUCs. All of the discussion for Alternative B compared to Alternative A (Section 4.1.2) would apply for Alternative C, as both Alternative B and C involve a discontinuation of the GPP Program.

The new service offering included in Alternative C is primarily intended to help ensure that future private-scale solar systems would be installed properly and safely. By establishing a QCN of vetted solar installers, installation standards, inspection requirements, and a more standardized interconnection process, TVA would help its EUCs obtain high-quality private-scale solar installations. The potential benefits of this service offering to EUCs is discussed in Section 4.2.3.

While the primary purpose and direct impact of the service offering is ensuring installation quality and safety, the program would likely have an indirect impact on energy production and use by stimulating an increase in private-scale solar systems compared to Alternative B. Quality and safety concerns are second only to financial concerns among issues cited by potential adopters (Moezzi et al. 2017). The service offering would help to alleviate EUCs' quality and safety concerns. In addition, the service offering would provide non-biased

[24] This occurs directly in BTM because energy use from LPCs is reduced. It occurs indirectly in GPP because the customer receives an energy credit for the energy they generate.
[25] Projection 1, extension of GPP trends, did not consider BTM.

information to help EUCs better understand the decision to install solar. Therefore, some potential EUCs may adopt BTM who would otherwise not have, as discussed below.

A review of strategies employed by solar PV incentive programs across the U.S., which was prepared by the Lawrence Berkeley National Laboratory, includes a list of 10 recommendations for best practices to promote well-performing solar PV systems (Barbose et al. 2008). These recommendations include building customer knowledge and capabilities, ensuring applicable codes are followed and enforced, and more thorough certification and testing protocols. Alternative C addresses several of these recommendations.

A survey conducted by the National Renewable Energy Laboratory (NREL) between 2014 and 2015 across 3,600 respondents and 4 states found that, of those individuals who were considering installing solar panels at their residence but did not ultimately install a system, 28% claimed they had low levels of trust in available information sources, 15% were concerned with damage to their roof, and 31% perceive solar as ‘risky’ (Moezzi et al. 2017). Furthermore, when those who had seriously considered solar installations (but opted against) were asked why they did not install solar, 44% said they stopped consideration based partially on concerns over ”equipment quality and reliability over time,” while 40% stopped consideration because it ”risked damage to their roof” (Moezzi et al. 2017). This research aligns with market research commissioned by TVA, which found that about 90 percent of study participants rated qualified contractors as important and over 60 percent rated qualified contractors as extremely important, the highest of any factor tested. The service offering in Alternative C should alleviate these types of concerns for some customers.

In addition, other research has shown that non-financial factors can impact private-scale solar adoption. For example, Bollinger and Gillingham (2012) have shown that social effects (i.e. interacting with one’s peers) significantly impacts solar adoption in California. Controlling for other important factors, the authors found that one additional solar installation in a zip code increases the adoption of solar elsewhere in the same zip code.

Peer-reviewed research suggests that public certifications of installers, similar to the QCN of vetted installers in the Alternative C service offering, increased the potential for solar adoption. We did not find published papers from the United States on this topic and thus rely on published literature from other countries. For example, Simpson and Clifton (2015) found that there is a general lack of trust toward solar industry members in Western Australia, and that these concerns could be alleviated by certification schemes. The authors conclude that independent information (like that from governmental agencies) can be critical in increasing solar demand by distributed consumers. Similarly, Verma et al. (2016), found that for the Indian residential solar market, “a trusted certification scheme could turn a vicious cycle of consumer skepticism into a virtuous cycle”.

In summary, Alternative C would have many of the same minor impacts on energy production and use as Alternative B, resulting from the discontinuation of the GPP Program and the likely increase in BTM installations as EUCs that would have adopted GPP in Alternative A choose BTM in Alternatives B and C. Compared to Alternative B, Alternative C would likely result in more BTM installations because some EUC’s concerns over system quality and safety would be alleviated. Increasing BTM installations is not a goal of the service offering, and TVA expects any increase in BTM to be minor compared to Alternative B.

4.2 Socioeconomics and Environmental Justice

4.2.1 Alternative A – No Action Alternative (GPP Program Continues)

In Alternative A, the GPP Program would continue as implemented in 2019.[26] Projections indicate that residential and commercial EUCs would likely enroll at similar rates to recent years from 2019 through 2028, and then new enrollment is projected to decline to zero over between 2029 and 2038 (Section 4.1.1).

Current GPP participants would not be directly affected by continuation of the GPP Program in Alternative A, as the terms of their 20-year agreements would continue. However, they may seek to enroll in GPP again once their current 20-year agreement expires. In this case, impacts among current enrollees would be similar to impacts among those who would have been future GPP participants as discussed in the following paragraph.

Alternative A would directly impact EUCs that would enroll in GPP in the future. Future GPP participants would benefit by being able to sell electricity to TVA at a fixed rate for a 20-year contract. Although not all GPP participants would fully recover the costs of their solar systems, many EUCs would not participate if they did not expect a positive financial return.[27] The financial return depends on individual-specific factors, including the discount rate.[28] Based on the inputs underlying the simple payback periods in Section 4.1.1.3, a typical business owner with a solar installation of 10 kW could save approximately $7,600 over the 20-year contract period.[29] At a 7 percent discount rate, this would represent a $2,700 loss in present-valued dollars. A typical residential solar installation of 6 kW would result in a loss of approximately $1,100 over the 20-year contract period at a 0 percent discount rate and a $6,800 loss at a 7 percent discount rate.[30] A loss projected for a typical residential EUC at a zero discount rate is consistent with the projected simple payback periods in Section 4.1.1.3. Any gains or losses would be spread over 20 years. Given that most participants in GPP would be commercial EUCs or residential EUCs with above-average incomes, these values are considered minor.

Alternative A could indirectly impact non-participating EUCs if GPP enrollment was significant enough to induce cost-shifting. Projected GPP enrollment represents a small proportion of TVA's total capacity and energy generation and the continuation of the GPP Program would have minor impacts on energy production and use (see Section 4.1). Any changes in TVA's costs of operating its facilities would not be discernable. The energy credits paid to GPP participants are a cost paid by TVA, and this cost ends up being spread across all EUCs in the TVA PSA.

In the upper bound scenario, future GPP enrollment included 197.5 MW of capacity and about 314 GWh of energy generation in 2038 (Section 4.1.1.1). The best projection is about one-third of the upper bound scenario (Section 4.1.1.4). TVA previously estimated that DER results in cost-shifting of about $71,000 per MW capacity (TVA 2018).[31] TVA Assuming that

[26] The only exception is that the annual limit for new capacity would revert to 10 MW rather than the 7.5 MW offered in 2019 (See Section 2.1.1).
[27] Moezzi et al. (2017) found that financial return was the most important factor considered by potential private-scale solar adopters.
[28] The discount rate indicates a consumer's time preference of money. At a discount rate of zero, a consumer is indifferent between some amount of money today and any time in the future. At a discount rate of 7 percent, a consumer is indifferent between a payment of $1.07 in one year and a payment of $1.00 today.
[29] Savings means the total GPP energy credit payments minus the total costs of the system, including installation and O&M.
[30] Individual-specific factors could result in a positive return for some customers.
[31] The 2018 study estimated $50 million in cost-shifting from 700 MW of installed capacity.

a similar ratio applies to future GPP participation, cost-shifting in 2038 would be about $14 million annually in the upper bound scenario and $5 million annually in the best projection scenario.

TVA serves about 4.8 million residential and commercial EUCs. Assuming the cost-shifting was spread evenly across all EUCs, electricity bills would increase by $2.92 per year in the upper bound scenario and $1.02 per year in the best projection scenario. These values are minor to most EUCs in the TVA PSA, although for some low-income households, any increase in energy costs may be a burden. Cost-shifting is considered minor for most EUCs at the individual level, and the total cost-shifting of $5 to $14 million annually is considered a minor negative impact, the vast majority of which would accrue to non-GPP participants.

In summary, Alternative A would result in minor positive direct financial impacts to EUCs that would enroll in GPP and shift costs toward non-enrollees. The cost-shifting that would occur in Alternative A tends to benefit commercial EUCs and residential EUCs with above-average incomes at the expense of all other EUCs, including low-income residential EUCs.[32] In absolute terms, cost-shifting is spread evenly over EUCs in the TVA PSA. From this perspective, there is no disproportionate impact on low-income or minority residents. However, any financial impact may represent a greater burden on low-income residents, simply because it is a higher proportion of their incomes. While low-income residents have the potential to have a higher burden in this relative sense, the absolute amounts are low ($1 to $3 per year) and the adverse impact of cost-shifting is considered minor. TVA therefore concludes that there are no disproportionately high adverse impacts to low-income or minority populations in the TVA PSA as a result of Alternative A.

On balance, Alternative A results in negative socioeconomic impacts on residential and commercial EUCs in the TVA PSA. Alternatives B and C, which both discontinue the GPP Program, reduce these negative impacts.

4.2.2 Alternative B – Discontinue GPP Program without Replacement Program

In Alternative B, new GPP Program enrollment would be discontinued at the end of 2019. Existing customers' enrollments and PAs based on applications received by December 31, 2019 would not be affected. There would be no direct impacts to existing GPP participants or those that apply by December 31, 2019. At the end of the term of their PA agreements, impacts among these would be similar to impacts among those discussed below.

Potential future participants would be directly affected compared to Alternative A. They would no longer have the option to enroll in GPP, eliminating a future opportunity to achieve financial benefits. This is a minor negative impact among future enrollees compared to Alternative A, in which the GPP Program would continue. However, it is important to note that these EUCs would be made no worse off than they are today.

Alternative B would eliminate future cost-shifting resulting from the GPP Program by ending the subsidy to GPP participants. Cost-shifting resulting from existing PAs and applications received by December 31, 2019, would continue for the term of those PAs, however. In addition, future cost-shifting could still occur if EUCs that would have enrolled in GPP in Alternative A choose to install BTM if the GPP Program is discontinued. If these EUCs install the same amount of BTM capacity instead, cost-shifting would be lower than in

[32] See TVA 2018 for additional discussion of how cost-shifting can affect low-income and minority EUCs.

Alternative A.[33] However, the cost-shifting would be wholly attributable to private actions and decisions, rather than being influenced by TVA subsidies through the GPP Program. Cost-shifting would be negligibly smaller under Alternative B because TVA would no longer pay GPP energy credits (to potential future participants), which are very small on an annual basis.[34]

Therefore, Alternative B would have fewer adverse socioeconomic impacts than Alternative A.

4.2.3 Alternative C – Discontinue GPP Program and Present New Offering

In Alternative C, TVA would discontinue the GPP Program at the end of 2019 and would implement a new service offering. Existing customers' enrollments and PAs based on applications received by December 31, 2019 would not be affected. There would be no direct negative impacts to existing GPP participants or those that apply by December 31, 2019. At the end of the term of their PA agreements, impacts among these participants would be similar to impacts among those discussed below.

The direct negative impacts on future GPP participation and the potential positive impacts on EUCs resulting from reducing cost-shifting would be minor as described for Alternative B. As with Alternative B, there would be no disproportionately high adverse impacts on low-income or minority populations within the TVA PSA.

The replacement service offering is expected to result in additional positive impacts compared to Alternative B. The offering would focus on the quality and safety of private-scale solar installations by establishing a network of vetted installers and installation standards, requiring inspections, and providing information on installation and disposal to EUCs. Increasing safety is the main benefit of Alternative C. Safety benefits would mainly accrue to future EUCs who install private-scale solar systems and to TVA and LPC linemen.

Another benefit of Alternative C would be providing additional information to EUCs who are considering installing private-scale solar systems. Alternative C is expected to increase the number of private-scale solar installations compared to Alternative B (see section 4.1.3). Assuming these customers would only install solar if they expect the benefits to outweigh the costs, these customers would benefit from Alternative C compared to Alternative B and are expected to have minor positive financial impacts related to savings on electricity bills.[35]

The information on proper disposal of solar systems provided in Alternative C could benefit all existing EUCs with private-scale solar systems, including those enrolled in GPP, DPP, or who have BTM installations.

Finally, Alternative C would provide benefits to TVA and LPCs in terms of better information for planning purposes regarding the number and capacity of BTM solar installations. Alternative C is therefore preferred to both Alternatives A and B.

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[33] This is because GPP systems send all electricity generated to the grid, while BTM systems do not use all of the electricity produced. Therefore, a similar amount of BTM capacity would result in a smaller reduction in energy generated by TVA, which would result in less cost-shifting.

[34] Under the upper bound scenario, GPP credits would be about $28,000 in 2038 (313.8 MWh x 1000 kWh/MWh x $0.09/kWh = $28,242. This would be less than $0.01 per year across the 4.8 million EUCs in the TVA PSA.

[35] This statement assumes BTM solar installations, in which EUCs directly use energy from their systems, thereby reducing the amount of electricity they purchase from LPCs.

4.3 Air Resources

4.3.1 Alternative A – No Action Alternative (GPP Program Continues)

Continuation of the GPP Program has the potential to impact air resources primarily through changes in total energy generation or the renewable to non-renewable energy mix ratio. In general, increased GPP enrollment would add renewable solar generation capacity to the TVA PSA, which has potential to reduce the utilization of non-renewable generation and result in a positive impact on air resources by reducing emissions.

However, as discussed in Section 4.1.1, projections of future GPP enrollment represent a small fraction of both the total and renewable energy generation in the TVA PSA. Such a small increase in total generation is unlikely to change how TVA conducts its energy generation operations or require TVA to alter its generation systems. In addition, if any alterations were to be necessary, it is highly unlikely that TVA operations could attribute those changes to GPP enrollment specifically, given the number of other factors that influence TVA power generation operations. As such, there would be no discernable changes to TVA's energy generation operations. Continuation of the GPP Program under Alternative A would therefore not have a discernable impact on air resources in the TVA PSA compared to current conditions. Current trends in air quality would continue.

4.3.2 Alternative B – Discontinue GPP Program without Replacement Program

Discontinuation of the GPP Program in Alternative B could result in a loss of future renewable energy generation compared to Alternative A, but would have no impact on current conditions. As discussed in Section 4.1.1, projections of future GPP enrollment represent a small fraction of both the total and renewable energy generation in the TVA PSA. As such, there would be no discernable changes to TVA's energy generation operations that could be attributed to the discontinuation of the GPP Program. Discontinuation of the GPP Program under Alternative B would therefore not have a discernable impact on air resources in the TVA PSA compared to Alternative A or current conditions. Current trends in air quality would continue. As discussed in Section 4.1.2, some future GPP participants under Alternative A may choose to install BTM solar under Alternative B. BTM solar installations have potential to reduce the utilization of non-renewable generation, reducing the potential for adverse impacts on air resources.

4.3.3 Alternative C – Discontinue GPP Program and Present New Offering

Impacts to air resources in Alternative C would be similar to those described for Alternative A. As discussed in Section 4.1.1, projections of future GPP enrollment represent a small fraction of both the total and renewable energy generation in the TVA PSA. As such, there would be no discernable changes to TVA's energy generation operations that could be attributed to the discontinuation of the GPP Program. Discontinuation of the GPP Program under Alternative C would therefore not have a discernable impact on air resources in the TVA PSA compared to current conditions and Alternatives A and B. Current trends in air quality would continue.

As discussed in Section 4.1.3, Alternative C is expected to result in more private-scale solar than Alternative B. Therefore, Alternative C could have a positive impact on air resources compared to Alternative B because more installations may reduce the utilization of non-renewable generation.

4.4 Water Resources

4.4.1 Alternative A – No Action Alternative (GPP Program Continues)

Increased GPP enrollment would add renewable solar generation capacity to the TVA PSA, which could reduce the utilization of non-renewable generation and result in a positive impact on water resources by offsetting other power generation that may have greater water impacts due to water use, particularly natural gas and nuclear (TVA 2019b). As discussed in Section 4.1.1, projections of future GPP enrollment represent a small fraction of both the total and renewable energy generation in the TVA PSA. As such, there would be no discernable changes to TVA's energy generation operations. Continuation of the GPP Program under Alternative A would therefore not have a discernable impact on water resources in the TVA PSA compared to current conditions. Current trends in water quality would continue.

4.4.2 Alternative B – Discontinue GPP Program without Replacement Program

Discontinuation of the GPP in Alternative B could result in a loss of future renewable energy generation compared to Alternative A, and no impact compared to current conditions. As discussed in Section 4.1.2, some future GPP participants under Alternative A may choose to install BTM solar under Alternative B, which would reduce any potential negative impacts on water resources of Alternative B compared to Alternative A. As discussed in Section 4.1.1, projections of future GPP enrollment represent such a small fraction of both the total and renewable energy generation in the TVA PSA that there would be no discernable changes to TVA's energy generation operations. Discontinuation of the GPP Program under Alternative B would therefore not have a discernable impact on water resources in the TVA PSA compared to current conditions or Alterative A. Current trends in water quality would continue.

4.4.3 Alternative C – Discontinue GPP Program and Present New Offering

Impacts to water resources in Alternative C would be similar to those described for Alternative A. As discussed in Section 4.1.3, Alternative C is expected to result in more private-scale solar than Alternative B. The new service offering is expected to add renewable solar generation capacity to the TVA PSA, which, like Alternative A, could reduce the utilization of non-renewable generation and result in a positive impact on water resources by offsetting other power generation that may have greater water impacts due to water use. Again, enrollment in the program represents such a small fraction of both the total and renewable energy generation in the TVA PSA that there would be no discernable changes to TVA's energy generation operations. Current trends in water quality would continue.

4.5 Land Use

4.5.1 Alternative A – No Action Alternative (GPP Program Continues)

The private-scale solar systems that would typically enroll in GPP Program in the future are expected to be mostly "rooftop" systems, although some systems could be ground-mounted. In general, land conversion, clearing, or modification would not be required for rooftop systems. Ground-mounted systems, when installed on a lawn or other cleared land, would not result in significant land use conversion, clearing, or modification. Generally, each kW of solar panels requires approximately 100 square feet of land (Narasimhan 2019). Therefore, a typical 5 kW residential system would require 500 square feet of land. If 50 percent of the upper bound GPP capacity were ground-mounted, this would require

approximately 227 acres.[36] This is less than one percent of the more than 25,000 acres currently used to support energy production in the TVA PSA (see Section 3.5). This is considered a minor change in land use compared to current conditions because of GPP continuation.

4.5.2 Alternative B – Discontinue GPP Program without Replacement Program

Alternative B would discontinue new enrollment in the GPP Program, which would eliminate the potential land conversion or alteration for GPP systems in Alternative A. As discussed in Section 4.1.2, some EUCs may choose to install BTM installations if GPP is discontinued. If all EUCs switch to BTM systems, then land use impacts for Alternative B would be similar to those in Alternative A. However, it is more likely that only some future GPP participants would switch to BTM, in which case the land use impacts of Alternative B would be lower than those in Alternative A. In either case, potential land use impacts in Alternative B are minor.

4.5.3 Alternative C – Discontinue GPP Program and Present New Offering

Alternative C would discontinue new enrollment in the GPP Program that would reduce potential land use for solar installations compared to Alternative A. Alternative C is, however, expected to increase the number of private-scale solar installations compared to Alternative B. As with Alternative B, EUCs may switch to BTM installations. Overall, impacts in Alternative C are expected to be similar to or higher than those in Alternative B, but still represent a small fraction of the area used to support energy production in the TVA PSA. The potential land use changes in Alternative C are also considered minor.

4.6 Production of Solid and Hazardous Waste

4.6.1 Alternative A – No Action Alternative (GPP Program Continues)

Impacts potentially occurring from continuation of the GPP Program would be associated with changes in total energy use, the renewable to non-renewable energy mix, and/or wastes generated as part of system installation or disposal.

As of 2018, GPP capacity was about 110 MW and as discussed in section 4.1.1, the highest amount of future GPP Program enrollment would represent a small fraction of the total and renewable energy generation in the TVA PSA. Therefore, there would be minor changes on the production of solid and hazardous waste within the TVA PSA. System installation is comparable to other household building and maintenance and is not expected to generate significant solid or hazardous wastes.

Overall, Alternative A would result in a minor increase in the production of solid and hazardous waste compared to current conditions, a minor negative environmental impact.

4.6.2 Alternative B – Discontinue GPP Program without Replacement Program

Alternative B would eliminate future GPP enrollment. Therefore, any solid and hazardous waste resulting from future GPP participation would be eliminated compared to Alternative A, resulting in a minor positive impact. Assuming all EUCs switch to BTM systems, then solid and hazardous waste impacts for Alternative B would be similar to those in Alternative A, a minor increase and minor negative environmental impact. However, it is more likely that only some future GPP participants would switch to BTM, in which case solid and hazardous waste impacts of Alternative B would be lower than those in Alternative A. This

[36] 0.5 x 197.5 MW x 1000 kW/MW x 100 sqft/kW ÷ 43560 sqft/acre.

results in a lower minor increase in comparison to Alternative A, but still represents a minor negative environmental impact.

4.6.3 Alternative C – Discontinue GPP Program and Present New Offering

Like Alternative B, Alternative C would eliminate future GPP Program enrollment. Therefore, any solid and hazardous waste resulting from future GPP participation would be eliminated compared to Alternative A, a minor positive impact.

Alternative C is expected to result in more private-scale solar than Alternative B. The new service offered by Alternative C would include guidance on the proper disposal of solar panels. This guidance would be available to all DER adopters, including those enrolled in the GPP Program. Vellini et al. (2017) performed a life cycle assessment of the two most common types of PV panels. In both cases, they found that recycling panels at end-of-life, rather than landfilling them, materially reduces overall environmental impacts as well as life cycle energy usage. Similarly, Xu et al. (2018) discussed the status and benefits of recycling solar equipment, suggesting that effective recycling of end-of-life panels could improve the cost efficiency of new panel production.

Depending on the availability of recycling resources, providing better information to consumers about proper disposal could result in a minor reduction in solid and hazardous waste generation, compared to Alternatives A and B, which is a positive environmental impact.

4.7 Cumulative Impacts

As discussed in Section 4.1.1, the GPP Program represents a small fraction of the renewable and total energy generation within the TVA PSA. The environmental and social changes associated with the preferred alternative (Alternative C) discussed in Sections 4.1 through 4.6 are not discernable to minor, with some negative and some positive impacts. The main negative impacts of Alternative C (compared to Alternative A) is a loss of the opportunity for EUCs to enroll in GPP after the end of 2019, which affects a minor proportion of EUCs in the TVA PSA. In contrast, the positive impacts from a reduction in cost-shifting compared to Alternative A, would accrue to all EUCs. On balance, the positive impacts to the residents of the TVA PSA in Alternative C outweigh the negative impacts.

Other related actions conducted by TVA that may cumulatively affect consumer behavior and investment in DER include TVA economic development efforts, rate changes, and TVA energy efficiency programs for residences, businesses, and industries (e.g., EnergyRight Solutions). The actions of other Federal agencies may influence energy use in the Tennessee Valley, as well as the rate of investment in DER by private consumers. These include tax credits or deductions for renewable energy initiatives, trade tariffs applied to DER components, and programs by other Federal agencies (e.g., Department of Energy) addressing DER. While these Federal programs and policies influence the rate of adoption of DER, the fate of these programs and policies remain uncertain at this time. In addition, many LPCs may conduct related activities that influence customer behavior, investments in DER, and energy efficiency.

TVA utilizes its Integrated Resource Planning process to consider the cumulative market and social forces that these programs, as well as other relevant inputs, have on TVA's energy generation and to provide direction on how to best meet future electricity demand. The 2019 IRP provides an important discussion regarding past, present, and foreseeable activities that influence energy use, and the EIS that accompanied it describes cumulative

impacts from combining different scenarios and strategies (TVA 2019a; TVA 2019b). The impacts associated with the alternatives analyzed in this EA are bounded by analyses in TVA's IRP.

In general, there is a potential for Alternative B or C to contribute to the cumulative impacts of any actions, technological changes, or market forces that affect energy generation costs or use in the TVA PSA. Alternative B or C could contribute to cumulative impacts on environmental and socioeconomic resources in the TVA PSA. In general, the minor negative and positive impacts expected to result from Alternative B or C are not anticipated to result in significant cumulative environmental or socioeconomic impacts.

4.8 Unavoidable Adverse Environmental Impacts

No specific unavoidable adverse environmental impacts were identified. Environmental impacts from the alternatives are generally tied to the total energy production and mix of renewable and non-renewable energy sources. Because the changes in total energy use and the renewable to non-renewable mix under all three alternatives would be minor in the context of the TVA PSA, any unavoidable environmental impacts are expected to be minor.

4.9 Irreversible and Irretrievable Commitments of Resources

No irreversible or irretrievable commitments of resources have been identified.

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